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10 CFR 50.90

April 9, 2019

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

Limerick Generating Station, Units 1 and 2
Renewed Facility Operating License Nos. NPF-39 and NPF-85
NRC Docket Nos. 50-352 and 50-353

Subject: Revise the Technical Specifications for Permanent Extension of Types A and C Leak Rate Test Frequencies and Permanently Extend the Drywell Bypass Leakage Test Frequency

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit or early site permit," Exelon Generation Company, LLC (Exelon) requests an amendment for Renewed Facility Operating Licenses for the Limerick Generating Station (LGS), Units 1 and 2 (NPF-39 and NPF-85, respectively), to allow for permanent extension of the Type A and Type C leakage rate testing frequencies. The proposed change revises the LGS, Units 1 and 2 Technical Specification (TS) 6.8.4.g, "Primary Containment Leakage Rate Testing Program," and Surveillance Requirement (SR) 4.6.2.1.e which is associated with the drywell-to-suppression chamber bypass leak test.

The proposed change has been reviewed by the Limerick Plant Operations Review Committee in accordance with the requirements of the Exelon Quality Assurance Program.

Exelon requests approval of the proposed amendment by April 9, 2020.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b), Exelon is notifying the State of Pennsylvania of this application for license amendment by transmitting a copy of this letter and its attachments to the designated State Official.

Should you have any questions concerning this letter, please contact Tom Loomis at (610) 765-5510.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 9th day of April 2019.

Respectfully,

James Barstow

James Barstow
Director - Licensing and Regulatory Affairs
Exelon Generation Company, LLC

Attachments:
1. Evaluation of Proposed Change
2. Markup of Technical Specifications Page
3. Risk Assessment for LGS Regarding the ILRT (Type A) and DWBT Permanent Extension Request

cc:
USNRC Region I, Regional Administrator
USNRC Senior Resident Inspector, LGS
USNRC Project Manager, LGS
R. R. Janati, Pennsylvania Bureau of Radiation Protection

ATTACHMENT 1

EVALUATION OF PROPOSED CHANGE

SUBJECT: **Revise the Technical Specifications for Permanent Extension of Types A and C Leak Rate Test Frequencies and Permanently Extend the Drywell Bypass Leakage Test Frequency**

1.0 SUMMARY DESCRIPTION

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit or early site permit," Exelon Generation Company, LLC (Exelon) requests an amendment for Renewed Facility Operating Licenses for the Limerick Generating Station (LGS), Units 1 and 2 (NPF-39 and NPF-85, respectively), to allow for permanent extension of the Type A and Type C leakage rate testing frequencies. The proposed change revises Technical Specification (TS) 6.8.4.g, "Primary Containment Leakage Rate Testing Program," and Surveillance Requirement (SR) 4.6.2.1.e, for LGS, Units 1 and 2, to allow the following:

- Increase the existing Type A integrated leakage rate test (ILRT) program test interval from 10 years to 15 years in accordance with Nuclear Energy Institute (NEI) Topical Report (TR) NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 3-A (Reference 1) and the limitations and conditions specified in NEI 94-01, Revision 2-A (Reference 2).

- Adopts an extension of the containment isolation valve (CIV) leakage rate testing (Type C) frequency from the 60 months currently permitted by 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B, to a maximum 75-month frequency for Type C leakage rate testing of selected components, in accordance with NEI 94-01, Revision 3-A.

- Adopts the use of American National Standards Institute/American Nuclear Society ANSI/ANS 56.8-2002, "Containment System Leakage Testing Requirements" (Reference 3).

- Adopts a more conservative allowable test interval extension of nine months, for Type A, Type B, and Type C leakage rate tests in accordance with NEI 94-01, Revision 3-A.

- Extend the existing drywell-to-suppression chamber bypass leak rate test (DWBT) frequency from 120 months (10 years) to 180 months (15 years).

Specifically, the proposed change contained herein revises each of the LGS, Units 1 and 2 TS 6.8.4.g by replacing the references to Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program," (Reference 4) with a reference to NEI 94-01, Revision 3-A (Reference 1), and the limitations and conditions specified in NEI 94-01, Revision 2-A (Reference 2), as the documents used by LGS to implement the performance-based leakage testing program in accordance with Option B of 10 CFR 50, Appendix J.

This License Amendment Request (LAR) also proposes administrative changes to the exceptions listed in the LGS, Units 1 and 2, TS 6.8.4.g. The exception regarding the performance of the next LGS, Unit 1 Type A test to be performed no later than May 15, 2013, will be deleted as this Type A test has already occurred. Additionally, the exception regarding the performance of the next LGS, Unit 2 Type A test to be performed no later than May 21, 2014, will be deleted as this Type A test has already occurred. This LAR will also change the DWBT frequency required by LGS, Units 1 and 2 SR 4.6.2.1.e from 120 months (10 years) to 180 months (15 years) to align with the proposed Type A test frequency.

2.0 DETAILED DESCRIPTION

LGS, Unit 1 TS 6.8.4.g, "Primary 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 Leakage Test program,” dated September 1995, as modified by the following exception to NEI 94-01, Rev. 0, “Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J”:
>
> a. Section 9.2.3: The first Type A test performed after May 15, 1998 shall be performed no later than May 15, 2013.

LGS, Unit 2 TS 6.8.4.g, "Primary 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 Leakage Test program,” dated September 1995, as modified by the following exception to NEI 94-01, Rev. 0, “Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J”:
>
> a. Section 9.2.3: The first Type A test performed after May 21, 1999 shall be performed no later than May 21, 2014.

The proposed changes to LGS, Units 1 and 2 TS 6.8.4.g will replace the reference to RG 1.163 with a reference to NEI Topical Report NEI 94-01, Revisions 2-A and 3-A. This LAR also proposes administrative changes to one exception in both Units 1 and 2 TS 6.8.4.g. The Unit 1 TS 6.8.4.g exception regarding the performance of the next LGS, Unit 1 Type A test to be performed “no later than May 15, 2013,” is being deleted as this Type A test has already occurred. Additionally, the Unit 2 TS 6.8.4.g exception regarding the performance of the next LGS, Unit 2 Type A test to be performed “no later than May 21, 2014,” is being deleted as this Type A test has already occurred.

The proposed change revises LGS, Units 1 and 2 TS 6.8.4.g to read as follows (with recommended changes in **bold-type** for clarification purposes):

> 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 limitations and conditions specified in NEI 94-01, Revision 2-A, dated October 2008.**

LGS, Units 1 and 2 SR 4.6.2.1.e currently states,

> Drywell-to-suppression chamber bypass leak tests shall be conducted to coincide with the Type A test at an initial differential pressure of 4 psi and verify that the $A/\sqrt{k}$ calculated from the measured leakage is within the specified limit. If any drywell-to-suppression chamber bypass leak test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission. If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 24 months until two consecutive tests meet the specified limit, at which time the test schedule may be resumed.

By letter dated June 28, 1996 (Reference 5) as supplemented by letters dated November 4 and 5, 1996 (References 6 and 7, respectively) and December 9, 1996 (Reference 8), LGS submitted a request for changes to the Units 1 and 2 TS (Reference 5). The requested changes include revision of the TS to incorporate performance-based testing, in accordance with 10 CFR Part 50, Appendix J, “Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors,” Option B. As part of the request, LGS proposed maintaining the requirement to perform DWBTs at the same interval and coincident with the Appendix J Type A test. By letter dated January 24, 1997, the NRC issued Amendment No. 118 for LGS, Unit 1 and Amendment No. 81 for LGS, Unit 2 approving the use of Appendix J, Option B along with the corresponding frequency change to the DWBT (Reference 9). As a result of these TS amendments, Units 1 and 2 SR 4.6.2.1.e were revised as shown above to include wording to conduct the DWBT to “coincide with the Type A test.”

This LAR proposes to change the frequency of both the Type A test and DWBT to a maximum test interval of 15 years. However, this LAR does not propose any changes to the Units 1 and 2 SR 4.6.2.1.e, as the current wording meets the intent of the change to the DWBT interval of 15 years. The risk assessment for the extension of the DWBT is included in Appendix B of Attachment 3 of this submittal.

The marked-up TS pages for LGS, Units 1 and 2 TS 6.8.4.g are provided in Attachment 2.

Attachment 3 contains the plant specific risk assessment conducted to support this proposed change. This risk assessment followed the guidelines of RG 1.174, Revision 2 (Reference 10) and RG 1.200, Revision 2 (Reference 11). The risk assessment concludes that the increase in risk as a result of this proposed change is very small and is well within established guidelines.

3.0 TECHNICAL EVALUATION

3.1 Concrete Containment

3.1.1 Description of Primary Containment

A horizontal diaphragm slab divides the primary containment into two major volumes: the drywell and the suppression chamber. The drywell encloses the reactor vessel, reactor recirculation system, and associated piping and valves. The suppression chamber stores a large volume of water.

The primary containment is in the form of a truncated cone over a cylindrical section, with the drywell being the upper conical section and the suppression chamber being the lower cylindrical section. These two sections comprise a structurally integrated, reinforced concrete pressure vessel, lined with welded steel plate and provided with a steel domed head for closure at the top of the drywell. The diaphragm slab is a reinforced concrete slab structurally connected to the containment wall.

The primary containment is structurally separated from the surrounding reactor enclosure.

The concrete dimensions of the primary containment are as follows:

a. Inside Diameter
   1. Suppression chamber – 88’-0”
   2. Base of drywell – 86’-4”
   3. Top of drywell – 36’-4 ½”

b. Height
   1. Suppression chamber – 52’-6”
   2. Drywell – 87’-9”

c. Thickness
   1. Base foundation slab – 8’-0”
   2. Containment wall – 6’-2”

3.1.2 Base Foundation Slab

The containment base foundation slab is a reinforced concrete mat, the top of which is lined with carbon steel plate.

3.1.3 Reinforcement

The base foundation slab is reinforced with No. 18, Grade 60 rebar at the top and bottom faces. The maximum rebar spacing is 18 inches. Shear reinforcement consists of No. 8 and No. 9 vertical and inclined ties. Cadweld splices are used for splicing all main reinforcing bars.

3.1.4 Liner Plate and Anchorages

The steel liner plate is ¼-inch thick and is anchored to the concrete slab by structural steel beams embedded in the concrete and welded to the plate.

3.1.5 Reactor Pedestal and Suppression Chamber Column, Base Liner Anchorages

For the pedestal anchorage, Cadweld sleeves are welded to the top and bottom surfaces of the thickened base liner to permit anchoring of the pedestal vertical rebar into the base foundation slab. Metal studs are welded to the top and bottom surfaces of the thickened base liner in order to transfer radial and tangential shear forces from the pedestal to the base foundation slab. For the suppression chamber column anchorage, pipe caps are welded to the thickened base liner at the locations where the column anchor bolts penetrate the base liner, in order to ensure the leak-tight integrity of the base liner.

3.1.6 Containment Wall

The containment wall is constructed of reinforced concrete 6 feet, 2 inches thick, and is lined with carbon steel plate on the inside surface.

3.1.7 Reinforcement

The containment wall is reinforced with No. 18, Grade 60 rebar at the inner and outer faces. The inner rebar curtain consists of two meridional layers and one hoop layer. The outer rebar curtain consists of one meridional layer, two hoop layers, and two helical layers. Radial shear reinforcement consists of No. 6 horizontal and inclined ties. Cadweld splices are used for splicing all main reinforcing bars.

3.1.8 Liner Plate and Anchorages

The steel liner plate is ¼-inch thick and is anchored to the concrete wall by vertical stiffeners, using structural tees spaced horizontally every 2 feet, or less. Horizontal plate stiffeners provide additional stiffening.

Loads from internal containment attachments, such as beam seats and pipe restraints, are transferred directly into the containment concrete wall. This is accomplished by thickening the liner plate and attaching structural weldments that transfer any type of load to the concrete, without relying on the liner plate or its anchorages. Where internal containment attachment loads are large, the structural weldments penetrate the liner plate, rather than being welded to opposite sides of the liner plate. This eliminates the possibility of lamellar tearing.

3.1.9 Penetrations

Services and communication between the inside and outside of the containment are performed through penetrations. Basic penetration types include pipe penetrations, electrical penetrations, and access hatches (equipment hatches, personnel lock, suppression chamber, access hatches, and CRD removal hatch). Each penetration consists of a pipe sleeve with an annular ring welded to it. The ring is embedded in the concrete wall and provides an anchorage for the penetration to resist normal operating and accident loads. The pipe sleeve is also welded to the containment liner plate to provide a leak-tight penetration.

Meridional and hoop reinforcement is bent around typical penetrations. Additional local reinforcement in the hoop and diagonal directions is added at all large penetrations. Local thickening of the containment wall at penetrations is generally not required.

a. Pipe Penetrations

   There are two basic types of penetrations. For piping systems containing high temperature fluids, a sleeved penetration is furnished, providing an air gap between the containment concrete wall and the hot pipe. This air gap is large enough to maintain the concrete temperature below 200 degrees Fahrenheit in the penetration area. A flued head outside the containment connects the process pipe to the pipe sleeve. For piping systems containing low temperature fluid, a separate sleeve for the penetration is not furnished. For this type of penetration, the process pipe is welded directly to the two ends of the embedded pipe penetration.

b. Electrical Penetrations

   A typical electrical penetration assembly is used to extend electrical conductors through the containment. The penetrations are hermetically sealed and provide for leak testing at design pressure.

c. Equipment Hatches and Personnel Lock

   Two equipment hatches, with inside diameters of 12 feet, are furnished in the drywell wall. One of these equipment hatches includes a personnel lock. Additional meridional, hoop, helical, and shear reinforcement is used to accommodate local stress concentrations at the opening. The containment wall is thickened at the equipment hatches to accommodate the additional rebars.

d. Suppression Chamber Access Hatches

   Two access hatches, with internal diameters of 4 feet, 4 inches, are furnished in the suppression chamber wall.

e. Drywell Head Assembly

   The drywell head lower flange is anchored to the top of the drywell wall by rigid attachment to 108 meridional reinforcing bars in the inner curtain of the containment wall.

3.1.10 Internal Containment Attachments

The principal items attached to the containment wall from the interior are the diaphragm slab, beam seats, pipe restraints and the seismic truss.

a. Diaphragm Slab Embedments

The diaphragm slab is attached to the containment wall by a structural weldment at the junction of the two compounds. Cadwelding the diaphragm slab rebar to the top and bottom flanges of the structural weldment, transfers radial force and bending moment, carried by the diaphragm slab main reinforcement, to the containment wall. The top and bottom flanges of the structural weldment are embedded in the containment concrete wall and are anchored using structural steel anchors. Flexural shear in the diaphragm slab is transferred to the containment wall through the web of the structural weldment, which is welded to opposite sides of the thickened containment liner plate.

b. Beam Seat Embedments

Beam seats are provided to support the drywell platforms.

c. Pipe Restraint Embedments

Pipe restraints are provided to prevent pipe whip caused by rupture of high-energy piping.

d. Seismic Truss Support Embedments

The seismic truss provides lateral support for the reactor vessel and reactor shield.

3.1.11 External Containment Attachments

There are no major external structural attachments to the primary containment wall, except brackets providing vertical support for some of the reactor enclosure floor beams. These floor beams support checkered plate blowout panels and are small enough to not cause any vertical interaction between the containment structure and the reactor enclosure. In addition, the beam-to-bracket connections are sliding connections, preventing horizontal interaction between the containment structure and the reactor enclosure.

3.2 ASME Class MC Steel Components of the Containment

3.2.1 Drywell Head Assembly

The drywell head provides a removable closure at the top of the containment for reactor access during refueling operations. The drywell head assembly consists of a 2:1 hemi-ellipsoidal head and a cylindrical lower flange. The head is made of 1 ½-inch thick plate and is secured with eighty 2-¾ inch diameter bolts at the 4-inch-thick mating flange. The head-to-lower flange connection is made leak-tight by two replaceable gaskets. The space between the gaskets is provided with test connections to allow pneumatic testing from a remote location, outside the primary containment. The inside diameter of the drywell head at the mating flange is 37 feet, 7 ½ inches. A double-gasketed manhole is provided in the drywell head.

3.2.2 Equipment Hatches and Personnel Lock

Two 12-foot diameter equipment hatches are furnished in the drywell wall to permit the transfer of equipment and components into and out of the drywell. One hatch consists of a double-gasketed flange and a bolted dished door. The outer hatch is furnished with a personnel lock welded to the removable door. The personnel lock is 8 feet, 7 inches diameter cylindrical pressure vessel, with inner and outer flat bulkheads. Interlocked doors 2-feet, 6-inch wide by 6 feet high, with double tongue-and-groove single element compression seals, are furnished in each bulkhead. A quick-acting, equalizing valve vents the personnel lock to the drywell to equalize the pressure in the two systems when the doors are opened and then closed. The two doors in the personnel lock are mechanically interlocked to prevent them from being opened simultaneously, and to ensure that one door is closed before the opposite door can be opened. The personnel lock has an ASME Code N-stamp.

3.2.3 Suppression Chamber Access Hatches

Two 4 feet, 4-inch diameter access hatches are furnished in the suppression chamber wall to permit personnel access, and the transfer of equipment and components into and out of the suppression chamber. Each hatch consists of a double-gasketed flange and a bolted flat cover.

3.2.4 Control Rod Drive Removal Hatch

One 3-foot diameter CRD removal hatch is furnished in the drywell wall to permit transfer of the CRD assemblies into and out of the drywell. The hatch is furnished with a double-gasketed flange and a bolted flat cover.

3.2.5 Piping and Electrical Penetrations

A portion of each of the penetration sleeves extends beyond the containment wall and is not backed by concrete. Therefore, the entire length of any penetration sleeve is considered an MC component, and as such, is designed in accordance with ASME Section III, subsection B.

3.3 Justification for the Technical Specification Change

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

The testing requirements of 10 CFR Part 50, Appendix J, provide assurance that leakage from the containment, including systems and components that penetrate the containment, does not exceed the allowable leakage values specified in the TS. Title 10 CFR Part 50, Appendix J also ensures that periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of the containment and the systems and components penetrating primary containment. The limitation on containment leakage provides assurance that the containment would perform its design function following an accident up to and including the plant design basis accident (DBA). Appendix J identifies three types of required tests:

1) Type A tests, intended to measure the primary containment overall integrated leakage rate;

2) Type B tests, intended to detect local leaks and to measure leakage across pressure-containing or leakage limiting boundaries (other than valves) for primary containment penetrations; and,

3) Type C tests, intended to measure containment isolation valve leakage rates.

Types B and C tests identify the vast majority of potential containment leakage paths. Type A tests identify the overall (integrated) containment leakage rate and serve to ensure continued leakage integrity of the containment structure by evaluating those structural parts of the containment not covered by Type B and C testing.

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

Also, in 1995, RG 1.163 (Reference 4) was issued. The RG endorsed NEI 94-01, Revision 0, (Reference 12) with certain modifications and additions. Option B, in concert with RG 1.163 and NEI 94-01, Revision 0, allows licensees with a satisfactory ILRT performance history (i.e., two consecutive, successful Type A tests) to reduce the test frequency for the containment Type A (ILRT) test from three tests in 10 years to one test in 10 years. This relaxation was based on an NRC risk assessment contained in NUREG-1493, (Reference 13) and Electric Power Research Institute (EPRI) TR-104285 (Reference 14) both of which showed that the risk increase associated with extending the ILRT surveillance interval was very small. In addition to the 10-year ILRT interval, provisions for extending the test interval an additional 15 months was considered in the establishment of the intervals allowed by RG 1.163 and NEI 94-01, but that this "should be used only in cases where refueling schedules have been changed to accommodate other factors."

In 2008, NEI 94-01, Revision 2-A (Reference 2), was issued. This document describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR Part 50, Appendix J, subject to the limitations and conditions noted in Section 4.0 of the NRC Safety Evaluation Report (SER) on NEI 94-01. The NRC SER was included in the front matter of this NEI report. 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 (Reference 4). It delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance testing frequencies. Justification for extending test intervals is based on the performance history and risk insights.

In 2012, NEI 94-01, Revision 3-A (Reference 1), was issued. This document describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR Part 50, Appendix J and includes provisions for extending Type A ILRT intervals to up to 15 years. NEI 94-01 has been endorsed by RG 1.163 and NRC SERs dated June 25, 2008 (Reference 15) and June 8, 2012 (Reference 16), as an acceptable methodology for complying with the provisions of Option B to 10 CFR Part 50. The regulatory positions stated in RG 1.163, as modified by NRC SERs 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 for 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 (AF) tests, schedule and review as described in NEI 94-01, Revision 3-A, Section 11.3.2.

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

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

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

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

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

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

3.3.2 Current LGS Primary Containment Leakage Rate Testing Program Requirements

10 CFR Part 50, Appendix J was revised, effective October 26, 1995, to allow licenses to choose containment leakage testing under either Option A, "Prescriptive Requirements," or Option B, "Performance-Based Requirements." On January 24, 1997, the NRC approved License Amendment Nos. 118 and 81 for LGS, Units 1 and 2, respectively (Reference 9) authorizing the implementation of 10 CFR Part 50, Appendix J, Option B for Types A, B and C tests.

Current Units 1 and 2 TS 6.8.4.g require that a program be established to comply with the containment leakage rate testing requirements of 10 CFR 50.54(o) and 10 CFR Part 50, Appendix J, Option B, as modified by approved exemptions. The program is required to be in accordance with the guidelines contained in RG 1.163. RG 1.163 endorses, with certain exceptions, NEI 94-01, Revision 0, as an acceptable method for complying with the provisions of Appendix J, Option B.

RG 1.163, Section C.1 states that licensees intending to comply with 10 CFR Part 50, Appendix J, Option B, should establish test intervals based upon the criteria in Section 11.0 of NEI 94-01 (Reference 12) rather than using test intervals specified in American National Standards Institute (ANSI)/American Nuclear Society (ANS) 56.8-1994 (Reference 17). Nuclear Energy Institute 94-01, Section 11.0 refers to Section 9, which states that Type A testing shall be performed during a period of reactor shutdown at a frequency of at least once per ten years based on acceptable performance history. Acceptable performance history is defined as completion of two consecutive periodic Type A tests where the calculated performance leakage was less than $1.0L_a$ (where L_a is the maximum allowable leakage rate at design pressure). Elapsed time between the first and last tests in a series of consecutive satisfactory tests used to determine performance shall be at least 24 months.

Adoption of the Option B performance-based containment leakage rate testing program altered the frequency of measuring primary containment leakage in Types A, B, and C tests but did not alter the basic method by which Appendix J leakage testing is performed. The test frequency is based on an evaluation of the "as found" leakage history to determine a frequency for leakage testing which provides assurance that leakage limits will not be exceeded. The allowed frequency for Type A testing as documented in NEI 94-01 is based, in part, upon a generic evaluation documented in NUREG-1493. The evaluation documented in NUREG-1493 included a study of the dependence of reactor accident risks on containment leak tightness for differing types of containment types, including a boiling water reactor (BWR) similar to the LGS containment structure. NUREG-1493 concluded in Section 10.1.2 that reducing the frequency of Type A tests (ILRT) from the original three tests per ten years to one test per 20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Types B and C testing, and the leaks that have been found by Type A tests have been only marginally above existing requirements. Given the insensitivity of risk to containment leakage rate and the small fraction of leakage paths detected solely by Type A testing, NUREG-1493 concluded that increasing the interval between ILRTs is possible with minimal impact on public risk.

3.3.3 LGS 10 CFR Part 50, Appendix J, Option B Licensing History

January 24, 1997

The NRC issued Amendment Nos. 118 (LGS, Unit 1) and 81 (LGS, Unit 2), which revised the Units 1 and 2 TS 6.8.4.g to incorporate 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors," Option B. (Reference 9)

February 20, 2008

The NRC issued Amendment Nos. 190 (LGS, Unit 1) and 151 (LGS, Unit 2), which revised the Units 1 and 2 TS 6.8.4.g to allow a one-time extension of the Type A leak rate test. The containment ILRTs were moved out to May 15, 2013 (Unit 1) and to May 21, 2014 (Unit 2). The changes reflected a one-time extension of the test interval for each unit from 10 to 15 years. (Reference 18)

3.3.4 Integrated Leakage Rate Testing (ILRT) History

As noted previously, LGS, Units 1 and 2 TS 6.8.4.g currently require Types A, B, and C testing in accordance with RG 1.163, which endorses the methodology for complying with Option B. Since the adoption of Option B, the performance leakage rates are calculated in accordance with NEI 94-01, Section 9.1.1 for Type A testing. Tables 3.3.4-1 and 3.3.4-2 below provide the past LGS Type A ILRT results. Tables 3.3.4-3 and 3.3.4-4 below provide the breakdown of the values used to determine the performance leakage rate and serve as a verification of the current extended ILRT interval for LGS, Units 1 and 2.

Table 3.3.4-1 – LGS Unit 1 Type A Testing History					
Test Date	95% UCL (wt.%/day)[4]	As-Found Leakage (wt.%/day)	Acceptance Criteria (La) (wt.%/day)	As-Left Leakage (wt.%/day)	Acceptance Criteria (0.75 La) (wt.%/day)
8/3/1984	0.213	Note 1	Note 1	0.1642	0.375
8/13/1987	0.131	Note 2	0.5	0.1469	0.375
11/23/1990	0.252	Note 5	0.5	0.287	0.375
5/13/1998	0.263	0.3751	0.5	0.307	0.375
3/17/2012	0.139	0.2688	0.5	0.2318	0.375

Table 3.3.4-2 – LGS Unit 2 Type A Test History					
Test Date	95% UCL (wt.%/day)[4]	As-Found Leakage (wt.%/day)	Acceptance Criteria (La) (wt.%/day)	As-Left Leakage (wt.%/day)	Acceptance Criteria (0.75 La) (wt.%/day)
5/6/1989	0.218	Note 1	Note 1	0.233	0.375
3/9/1993 Note 3	0.215	Note 5	0.5	0.2586	0.375
5/21/1999	0.2965	0.3584	0.5	0.3272	0.375
4/14/2013	0.252	0.3643	0.5	0.3643	0.375

Note 1: This was a pre-operational test; therefore, no AF leak rate calculated.

Note 2: The AF test results failed to meet the acceptance criteria of 0.500wt.%/day.

Note 3: The test method used was the Total Time Method, as described in ANSI N45.4-1972, "Leakage-Rate Testing of Containment Structures for Nuclear Reactors" and Bechtel Topical Report BN-TOP-1, Revision 1, "Testing Criteria for Integrated Leak Rate Testing of Primary Containment Structures for Nuclear Power Plants."

Note 4: The upper confidence limit (UCL) is a calculated value determined from test data that places a statistical upper bound on the true leakage rate. The UCL is calculated at a 95% confidence level in ANSI/ANS 56.8. From this 95% UCL leakage rate value, both the as-left (AL) and then AF ILRT leakage rates are determined. Corrections are made to the 95% UCL leakage rate for changes in the net free volume due to changes in containment sub-volume water levels and valves not in accident positions (Types B and C penalties) during the test.

Note 5: LGS does not maintain records of Types B and C leak rate summations for RFOs earlier than 1996. Therefore, leakage savings are not known and the AF leak rate cannot be calculated.

Table 3.3.4-3 – Verification of Current Extended ILRT Interval for LGS, Unit 1						
Test Date	**95% UCL Leakage Rate (wt.%/day)**	**Water Level Volume Corrections (wt.%/day)**	**Corrections for valves isolated during Test (wt.%/day)**	**Types B and C Penalties Due to Isolated Vents and Drains + Misc. Leakage (wt.%/day)**	**Performance Leak Rate (Acceptance Criteria ≤ 0.5 wt.%/day)**	**Test Method**
5/13/1998	0.263	0.00948	0.0000	0.03448	0.3070	Mass Pt.
3/17/2012	0.139	-0.00845	0.0000	0.10115	0.2318	Mass Pt.

Table 3.3.4-4 – Verification of Current Extended ILRT Interval for LGS, Unit 2						
Test Date	**95% UCL Leakage Rate (wt.%/day)**	**Water Level Volume Corrections (wt.%/day)**	**Corrections for valves isolated during Test (wt.%/day)**	**Type B and C Penalties Due to Isolated Vents and Drains + Misc. Leakage (wt.%/day)**	**Performance Leak Rate (Acceptance Criteria ≤ 0.5 wt.%/day)**	**Test Method**
5/21/1999	0.2965	0.0000	0.0000	0.0316	0.3272	Mass Pt.
4/14/2013	0.252	-0.0123	0.0000	0.1246	0.3643	Mass Pt.

3.3.5 Bypass Leak Rate Test Risk Assessment

Background:

The following steps are used to perform the analysis for the DWBT interval extension:

- Review the design basis
- Review historical test results
- Develop qualitative technical justification of change
- Perform deterministic calculations
- Perform risk assessment of interval change

3.3.5.1 LGS Mark II Pressure Suppression Containment Design

LGS incorporates a Mark II containment with the drywell located over the suppression chamber and separated by a diaphragm slab. The suppression chamber contains a pool of water having a depth that varies between 22 feet and 24 feet, 3 inches during normal operation. Eighty-seven downcomers and 14 main steam safety/relief valve (SRV) discharge lines penetrate the diaphragm slab and terminate at a pre-designed submergence within the pool. During a loss of coolant accident (LOCA) inside containment, the containment design directs steam from the drywell to the suppression pool via the downcomers through the pool of water to limit the maximum containment pressure response to less than the design pressure of 55 psig. The effectiveness of the LGS pressure suppression containment requires that the leak path from the drywell to the suppression chamber airspace be minimized. Steam that enters the suppression pool airspace through the leak paths will bypass the suppression pool and can result in a rapid post-LOCA increase in containment pressure depending on the size of the bypass flow area.

The design value for leakage area is determined by analyzing a spectrum of LOCA break sizes. For each break size there is a limiting leakage area. In determining the limiting leakage area, credit is taken for the capability of operators to initiate drywell and suppression pool sprays after a period of time sufficient for them to realize that there is a significant bypass flow. The effect of suppression pool bypass on containment pressure response is greatest with small breaks. The design value of 0.0500 square feet for LGS represents the maximum leakage area that can be tolerated for that break size that is most limiting with respect to suppression pool bypass.

LGS TS requirements conservatively specify a maximum allowable bypass area of 10 percent of the design value of 0.0500 square feet. The TS limit provides an additional factor of 10 safety margin above the conservatisms taken in the steam bypass analysis. The DWBT verifies that the actual bypass flow area is less than or equal to the TS limit.

3.3.5.2 Historical Test Results

A review of the past test history for the DWBT has identified no failures. Tables 3.3.5.2-1 and 3.3.5.2-2 below provide the historical DWBT test results at LGS, Units 1 and 2:

Table 3.3.5.2-1 – Unit 1 DWBT Test Historical Results

Year	Measured Leakage (ft^2)	Acceptance Criteria (ft^2)
1984	0.00026	0.005
1987	0.00005133	0.005
1990	0.000278	0.005
1998	0.000075	0.005
2012	0.000151	0.005

Table 3.3.5.2-2 – Unit 2 DWBT Historical Results

Year	Measured Leakage (ft^2)	Acceptance Criteria (ft^2)
1989	0.000069	0.005
1993	0.000076	0.005
1999	0.000012	0.005
2013	0.000137	0.005

The history of test results indicates that the typical leakage is about an order of magnitude or more below the acceptance criteria (which is set at an order of magnitude below the design basis limit). This excellent history combined with the conservatism included in the allowable leakage rate helps to support the qualitative justification provided below, and also helps support the low likelihood of large undetected bypass leakage in the risk assessment.

3.3.5.3 Qualitative Justification for DWBT Interval Extension

Several potential bypass leakage pathways exist:

- Leakage through the diaphragm floor penetrations (SRV) discharge line (downcomers),
- Cracks in the diaphragm floor/liner plate,
- Cracks in the downcomers that pass through the suppression pool airspace,
- Valve seat leakage in the four sets of drywell-to-suppression chamber containment vacuum breakers, and
- Seat leakage of isolation valves in piping connecting the drywell and the suppression chamber air space.

A previous assessment demonstrated that the most likely source of potential bypass leakage is the four sets of drywell-to-suppression chamber vacuum breakers. Each set consists of two vacuum breakers in series, flange mounted to a tee off the downcomers in the suppression chamber air space. The DWBT is currently performed on a schedule consistent with the ILRT. However, TS 4.6.2.1.f requires that the vacuum breaker leakage tests on all four sets of vacuum breakers be performed during all non-ILRT outages. Therefore, the most likely largest contributor to the bypass leakage will still be monitored each RFO and, thus, will continue to be managed and controlled to assure TS leakage is maintained.

The vacuum breaker leakage test and stringent acceptance criteria, combined with the historical negligible non-vacuum breaker leakage, and thorough periodic visual inspection provide an equivalent level of assurance as the DWBT that the drywell to suppression chamber bypass leakage can be measured and any adverse condition detected prior to a LOCA.

Summary of Changes in the Calculated Risk Metrics

Consistent with the ILRT assessment, the relevant figures of merit are change in large early release frequency (LERF), population dose, and conditional containment failure probability (CCFP). Additionally, the DWBT extension will also lead to a change in core damage frequency (CDF). The results for these figures of merit from the DWBT interval extension are show in Table B-6 of Attachment 3 of this submittal.

Based on the results of the deterministic studies and their probabilistic risk assessment (PRA) implications, the following can be defined:

- Increasing the DWBT interval is assumed to increase the probability of increased bypass leakage.
- There is a change in CDF associated with the possibility that a steam LOCA occurs with the increased drywell to wetwell bypass leakage and the containment pressurization is not mitigated. This is conservatively assumed to lead to containment failure and consequential loss of reactor pressure vessel makeup and results in core damage.
- The change in population dose associated with the other changes above is noted in Table B-6 of Attachment 3 of this submittal. The overall change in population dose is very small (~0.1%).
- There is also a change in the conditional containment failure probability (CCFP) with an increase in CDF. It is also noted that the increase in LERF is only from cases that were already containment failure cases (albeit shifted to a LERF release).

The risk metric changes to be compared are then:

- Δ CDF: 7.86E-10/year (yr)
- Δ LERF: 3.60E-09/yr
- Δ Person-Roentgen man equivalent (rem) dose rate: 0.015 person-rem/yr
- Δ CCFP: 0.003%

The changes in CDF and LERF meet the RG 1.174 (Reference 10) acceptance guidelines for very small risk change. The change in population dose rate is well below the acceptance criteria of ≤1.0 person-rem/yr or < 1.0% person-rem/yr defined in the EPRI guidance document. Change in CCFP of 0.003% is approximately two orders of magnitude below the EPRI guidance document acceptance criteria of less than 1.5%.

The change in risk metrics associated with the DWBT interval extension calculated above are based on internal events. The changes are very small and would not significantly change even if the potential impact from external events as calculated in Section 5.7.5 of Attachment 3 of this submittal were to be incorporated. That is, the change in CDF is negligible, the change in LERF from the DWBT is about 10% of the change in LERF from the ILRT, the change in person-rem from the DWBT is less than 25% of the change in person-rem from the ILRT extension, and the change in CCFP is just about 3% of the change in CCFP from the ILRT. Give the substantial margin that exists to the acceptance criteria even when external events are factored in, correspondingly including the DWBT results into the external events assessment would not change the conclusions of the analysis. In summary, the change in the DWBT interval extension from 3 in 10 years to 1 in 15 years is found to result in an acceptable change in risk.

3.3.6 Net Positive Suction Head (NPSH) for ECCS Pumps

NRC RG 1.1, Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps, prohibits design reliance on pressure and/or temperature transients expected during a LOCA for assuring adequate NPSH. The requirements of this guide are applicable to the High-Pressure Coolant Injection (HPCI), Low-Pressure Core Spray (CS), and Low-Pressure Coolant Injection (LPCI) pumps.

The Limerick Generating Station BWR design conservatively assumes 0 psig containment pressure and maximum expected temperatures of the pumped fluids. Thus, no reliance is placed on pressure and/or temperature transients to ensure adequate NPSH.

3.4 Plant Specific Confirmatory Analysis

3.4.1 Methodology

A plant specific confirmatory analysis was performed to provide a risk assessment of extending the currently allowed containment Type A ILRT to a permanent interval of fifteen years. The risk assessment follows the guidelines from NEI 94-01 (Reference 1), the methodology outlined in Electric Power Research Institute (EPRI) TR-104285 (Reference 14) as updated by the EPRI Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals (EPRI TR-1018243) (Reference 19), the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) findings and risk insights in support of a request for a plant's licensing basis as outlined in RG 1.174 (Reference 10), and 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 20). The format of this document is consistent with the intent of the Risk Impact assessment Template for evaluating extended ILRT intervals provided in the EPRI TR-1018243 (Reference 19).

Revisions to 10 CFR 50, Appendix J (Option B) allow individual plants to extend the ILRT Type A surveillance testing requirements from three-in-ten years to at least once per 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 was less than the normal containment leakage of $1.0L_a$ (allowable leakage).

The basis for a 10-year test interval is provided in Section 11.0 of NEI 94-01, Revision 0, and was 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," (Reference 13) 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 EPRI Report TR-104285 (Reference 14).

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 for a comparable BWR plant, that increasing the containment leak rate from the nominal 0.5 percent per day to 5 percent per day leads to a barely perceptible increase in total population exposure, and increasing the leak rate to 50 percent per day increases the total population exposure by less than 1 percent. Because ILRTs represent substantial resource expenditures, it is desirable to show that extending the ILRT interval will not lead to a substantial increase in risk from containment isolation failures to support a reduction in the test frequency for LGS. The current analysis is being performed to confirm these conclusions based on LGS-specific PRA models and available data.

Earlier ILRT frequency extension submittals have used the EPRI TR-104285 (Reference 14) methodology to perform the risk assessment. In October 2008, EPRI TR-1018243 (Reference 19) was issued to develop a generic methodology for the risk impact assessment for ILRT interval extensions to 15 years using current performance data and risk informed guidance, primarily NRC RG 1.174 (Reference 10). This more recent EPRI document considers the change in population dose, large early release frequency (LERF), and containment conditional failure probability (CCFP), whereas EPRI TR-104285 considered only the change in risk based on the change in population dose. This ILRT interval extension risk assessment for LGS, Units 1 and 2, employs the EPRI TR-1018243 methodology, with the affected system, structure, or component (SSC) being the primary containment boundary. Additionally, the methodology to evaluate the impact of concurrently extending the DWBT interval is performed consistent with previous one-time ILRT/DWBT extensions for BWR Mark II containment types, including the Limerick one-time assessment (Reference 21) and Columbia (Reference 22), which have been approved by the NRC.

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

Evaluation (SE). Table 3.4.1-1 addresses each of the four (4) limitations and conditions for the use of EPRI 1009325, Revision 2.

Table 3.4.1-1 – EPRI Report No. 1009325, Revision 2 Limitations and Conditions

Limitation/Condition **(From Section 4.2 of SE)**	**LGS 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.	LGS PRA technical adequacy is addressed in Section 3.4.2 of this LAR and Attachment 3, “Risk Impact Assessment of Extending the LGS ILRT/DWBT Interval, Appendix A, PRA Technical Adequacy.”
2.a The licensee submits documentation indicating that the estimated risk increase associated with permanently extending the ILRT surveillance interval to 15 years is small, and consistent with the clarification provided in Section 3.2.4.5 of this SE.	RG 1.174 provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines “very small” changes in risk as resulting in increases of CDF below 1.0E-6/year and increases in LERF below 1.0E-07/yr. “Small” changes in risk are defined as increases in CDF below 1.0E-05/yr and increases in LERF below 1.0E-06/yr. Since the ILRT extension was demonstrated to have negligible impact on CDF for LGS, the relevant criterion is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval for the base case with corrosion included is 3.23E-08/yr. In using the EPRI Expert Elicitation methodology, the change is estimated as 3.11E-09/yr. Both of these values fall within the very small change region of the acceptance guidelines in RG 1.174.

Table 3.4.1-1 – EPRI Report No. 1009325, Revision 2 Limitations and Conditions	
Limitation/Condition **(From Section 4.2 of SE)**	**LGS Response**
2.b Specifically, a small increase in population dose should be defined as an increase in population dose of less than or equal to either 1.0 person-rem per year or 1% of the total population dose, whichever is less restrictive.	The change in dose risk for changing the Type A test frequency from three-per-ten years to once-per-fifteen-years, measured as an increase to the total integrated dose risk for all internal events accident sequences for LGS, is 6.60E-02 person-rem/yr (0.36%) using the EPRI guidance with the base case corrosion included (Table 5.6-1). The change in dose risk drops to 1.16E-02 person-rem/yr (0.06%), when using the EPRI Expert Elicitation methodology (Table 6.2-2). The values calculated per the EPRI guidance are all lower than the acceptance criteria of ≤1.0 person-rem/yr or <1.0% person-rem/yr defined in Attachment 3, Section 1.3, of this submittal.
2.c In addition, a small increase in CCFP should be defined as a value marginally greater than that accepted in a previous one-time 15-year ILRT extension requests. This would require that the increase in CCFP be less than or equal to 1.5 percentage point.	The increase in the conditional containment failure frequency from the three in ten-year interval to one in fifteen years including corrosion effects using the EPRI guidance is 1.02%. This value drops to 0.10% using the EPRI Expert Elicitation methodology. Both of these values are below the acceptance criteria of less than 1.5% defined in Attachment 3, Section 1.3 of this submittal.
3. The methodology in EPRI Report No. 1009325, Revision 2, is acceptable except for the calculation of the increase in expected population dose (per year of reactor operation). In order to make the methodology acceptable, the average leak rate accident case (accident case 3b) used by the licensees shall be 100 L_a instead of 35 L_a.	The representative containment leakage for Class 3b sequences is 100La based on the guidance provided in EPRI Report No. 1009325, Revision 2. It should be noted that this is more conservative than the earlier previous industry Type A test interval extension requests, which utilized 35 L_a for the Class 3B sequences.

Table 3.4.1-1 – EPRI Report No. 1009325, Revision 2 Limitations and Conditions	
Limitation/Condition **(From Section 4.2 of SE)**	**LGS Response**
4. A license amendment request (LAR) is required in instances where containment over-pressure is relied upon for ECCS performance.	The BWR design conservatively assumes 0 psig containment pressure and maximum expected temperatures of the pumped fluids. Thus, no reliance is placed on pressure and/or temperature transients to ensure adequate NPSH. Reference 3.3.6 above for additional details.

3.4.2 PRA Technical Adequacy

A technical Probabilistic Risk Assessment (PRA) analysis is presented in this report to help support an extension of the LGS, Units 1 and 2 containment Type A ILRT and DWBT interval to fifteen years. The analysis follows the guidance provided in RG 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities" (Reference 11). The guidance in RG-1.200 indicates that the following steps should be followed to perform this study:

1. Identify the parts of the PRA used to support the application
    a. SSCs, operational characteristics affected by the application and how these are implemented in the PRA model.

    b. A definition of the acceptance criteria used for the application.

2. Identify the scope of risk contributors addressed by the PRA model
    a. If not full scope (i.e., internal and external), identify appropriate compensatory measures or provide bounding arguments to address the risk contributors not addressed by the model.

3. Summarize the risk assessment methodology used to assess the risk of the application
    a. Include how the PRA model was modified to approximately model the risk impact of the change request.

4. Demonstrate the Technical Adequacy of the PRA
    a. Identify plant changes (design or operational practices) that have been incorporated at the site, but are not yet in the PRA model and justify why the change does not impact the PRA results used to support the application.

b. Document peer review findings and observations that are applicable to the parts of the PRA required for the application, and for those that have not yet been addressed justify why the significant contributors would not be impacted.

c. Document that the parts of the PRA used in the decision are consistent with applicable standards endorsed by the RG. Provide justification to show that where specific requirements in the standard are not met, it will not unduly impact the results.

d. Identify key assumptions and approximations relevant to the results used in the decision-making process.

Items 1 through 3 are covered in the risk impact assessment in Attachment 3 of this submittal. The purpose of the technical adequacy discussion is to address the requirements identified in Item 4 above. Each of these items (plant changes not yet incorporated into the PRA model, relevant peer review findings, consistency with applicable PRA standards and the identification of key assumptions) is discussed below.

The risk assessment performed for the ILRT extension request is based on the current Levels 1 and 2 PRA models. Note that for this application, the accepted methodology involves a bounding approach to estimate the change in the LERF from extending the ILRT/DWBT interval. Rather than exercising the PRA model itself, separate evaluations that are linearly related to the plant CDF contribution are established. Consequently, a reasonable representation of the plant CDF that does not result in a LERF does not require that Capability Category (CC) II be met in every aspect of the modeling if the Category I treatment is conservative or otherwise does not significantly impact the results.

3.4.3 PRA Model Evolution and Peer Review Summary

3.4.3.1 Introduction

The 2017 versions of the LGS PRA models are the most recent evaluations of the Units 1 and 2 risk profiles at LGS for internal event (IE) challenges. The LGS 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 LGS PRA is based on the event tree / fault tree methodology, which is a well-known methodology in the industry.

Exelon employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA models for all operating Exelon 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 this approach as it applies to the LGS PRA.

PRA Maintenance and Update

The Exelon risk management process ensures that the applicable PRA model is an accurate reflection of the as-built and as-operated plants. This process is defined in the Exelon Risk

Management program, which consists of a governing procedure and subordinate implementation procedures. The PRA model update procedure delineates the responsibilities and guidelines for updating the full power internal events PRA models at all operating Exelon nuclear generation sites. The overall Exelon Risk Management program defines the process for implementing regularly scheduled and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, industry operating experience (OE), etc.), and for controlling the model and associated computer files. To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plants, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model.
- Maintenance unavailabilities are captured and their impact on CDF is trended.
- Plant-specific initiating event frequencies, failure rates and maintenance unavailabilities are updated approximately every four years.

In addition to these activities, Exelon risk management procedures provide the guidance for particular risk management maintenance activities. This guidance includes:

- Documentation of the PRA model, PRA products and bases documents.
- The approach for controlling electronic storage of Risk Management (RM) products including PRA update information, PRA models, and PRA applications.
- Guidelines for updating the full power, internal events PRA models for Exelon sites.
- Guidance for use of quantitative and qualitative risk models in support of the On-Line Work Control Process Program for risk evaluations for maintenance tasks (corrective maintenance, preventative maintenance, surveillance tests and modifications) on SSCs within the scope of the Maintenance Rule (10 CFR 50.65(a)(4)).

In accordance with this guidance, regularly scheduled PRA model updates nominally occur on an approximately 4-year cycle; longer intervals may be justified if it can be shown that the PRA continues to adequately represent the as-built, as-operated plant. The 2017 models were completed in July 2018.

As indicated previously, RG 1.200 (Reference 11) also requires that additional information be provided as part of the LAR submittal to demonstrate the technical adequacy of the PRA model used for the risk assessment. Each of these items (plant changes not yet incorporated into the PRA model, relevant peer review findings, and consistency with applicable PRA Standards) will be discussed in Sections 3.4.3.2 through 3.4.3.4 below.

3.4.3.2 Plant Changes Not Yet Incorporated into the PRA Model

A PRA updating requirements evaluation [(URE) - Exelon PRA model update tracking database] is created for all issues that are identified that could impact the PRA model. The

URE database includes the identification of those plant changes that could impact the PRA model.

A review of the open UREs indicates that there are no plant changes that have not yet been incorporated into the PRA model that would affect this application.

3.4.3.3 Consistency with Applicable PRA Standards

Several assessments of technical capability have been made for the LGS internal events PRA models. These assessments are as follows and further discussed in the paragraphs below.

The LGS PRA model for internal events received a formal industry peer review in November 1998. The model was updated in 2001 to address the significant findings from that review. Following that update, LGS was one of five nuclear plants that piloted application of RG 1.200; therefore, a site PRA gap analysis, which compared the LGS PRA to the requirements of the NRC-endorsed ASME PRA Standard, was completed in 2003 in support of the LGS pilot for Risk-Informed activities. Additionally, the LGS PRA model was subject to an NRC RG 1.200 pilot assessment in July 2004. Following the completion of the PRA model update in 2005, to strategically address the identified gaps, a peer review against draft Addendum B of the ASME PRA Standard (Reference 40) was performed in October 2005.

The Full Power Internal Events (FPIE) peer review performed in 2005 found that 97% of the supporting requirements evaluated “Met” CC II or better. There were seven (7) SRs that were assessed as “Not Met” and two (2) SRs that were assessed as meeting CC I. As noted in the peer review report, the majority of the findings were documentation related. Of the nine SRs, which were assessed as not meeting CC II or better, all were related to documentation issues in which two were also related to minor modeling enhancements that improve quantification. Additionally, one Finding was self-identified involving test and maintenance pre-initiators for a number of significant systems, but these were not derived from a formal review of procedures and practices.

In May of 2008, a focused peer review against Addendum B of the ASME PRA standard of the updated Internal Flooding (IF) analysis was performed. The IF peer review encompassed a review of the internal flood at-power PRA, consistent with the scope of the ASME PRA Standard RA-Sb-2005 (Reference 41) as endorsed and clarified at the time by the NRC in RG 1.200, Revision 1 (Reference 24). Of the 50 SRs evaluated, there were eight (8) that were assessed as “Not Met” and three (3) SRs, which did not meet CC II or better. These 11 SRs that were either “Not Met” or CC I were mostly related to minor model enhancements and documentation issues.

The 2005 FPIE peer review findings and the 2008 internal flood peer review findings were addressed in the LGS PRA, and in July, 2016, a review of the peer review findings and the resolutions was performed by an independent review team. The independent review team concluded that, for the FPIE, three findings were not resolved (and one open item was not reviewed). Two of the four findings are documentation related, and one of the findings can be addressed by a minor model change. For the IF findings, the review team concluded that two findings were resolved, one finding was not resolved and that eight findings were partially resolved. The nine unresolved IF findings are mostly related to minor model enhancements and documentation issues.

Additionally, a gap assessment to the current standard, ASME/ANS RA-Sa-2009 (Reference 23), and RG 1.200, Revision 2 (Reference 11) has been performed. The gap assessment did not identify any deficiencies that were not identified by the peer reviews or were not previously self-identified with respect to the new standard, and the remaining open items are consistent with the 2016 independent review team conclusions.

3.4.3.4 Applicability of Peer Review Findings and Observations

The remaining set of open or partially resolved findings from the independent review team assessment are described in Table A-1 of Attachment 3 of this submittal for internal events and internal flooding with their impact on this application noted. The current status reflects what has been done following completion of the 2017 model update where most of the remaining findings have been addressed.

3.4.3.5 External Events

Although EPRI TR 1018243 (Reference 19) recommends a quantitative assessment of the contribution of external events (for example, fire and seismic) where a model of sufficient quality exists, it also recognizes that the external events assessment can be taken from existing, previously submitted and approved analyses or another alternate method of assessing an order of magnitude estimate for contribution of the external event to the impact of the changed interval. Based on this, currently available information, for external events models, was referenced, and a multiplier was applied to the internal events results based on the available external events information. This is further discussed in Section 5.7 of Attachment 3 of this submittal.

A discussion of the unscreened external events contributors (i.e., internal fire hazards and seismic hazards) follows.

Internal Fire Hazards

The LGS Fire PRA (FPRA) peer review was performed November 2011 using the NEI 07-12 Fire PRA peer review process (Reference 25), the ASME PRA Standard, ASME/ANS RA-Sa-2009 (Reference 23) and RG 1.200, Revision 2 (Reference 11). The purpose of this review was to establish the technical adequacy of the FPRA for the spectrum of potential risk-informed plant licensing applications for which the FPRA may be used. The 2011 LGS FPRA peer review was a full-scope review of all of the technical elements of the LGS at-power FPRA against all technical elements in Part 4 of the ASME/ANS PRA Standard, including the referenced internal events SRs. The peer review noted a number of facts and observations (F&Os). The findings were addressed in the LGS FPRA and in July 2016, an independent review team performed a review of the FPRA peer review findings and the resolutions. The independent review team concluded that 14 of the findings were either partially resolved or still open. The independent review team did not assess an additional five findings since they were assessed as being open prior to the independent review.

The remaining set of open or partially resolved findings from the independent review team assessment are described in Table A-2 of Attachment 3 of this submittal for the internal fire hazard group and their impact on this application noted.

Seismic Hazards

A seismic CDF PRA model is not maintained for Limerick. As noted in Section 5.7.2 of the main body of the LGS ILRT risk assessment (Attachment 3), recent NRC work documented in Reference 46 of the main body provides seismic CDF information. The updated 2008 USGS Seismic Hazard Curves provide a weakest link CDF model. Table D-1 lists the postulated core damage frequencies using the updated 2008 USGS Seismic Hazard Curves. The weakest link model using the curve for LGS resulted in a CDF of 5.3E-05/yr. As noted in Section 5.7.2, this is an extremely conservative value, and as such, half of that value (2.65E-05/yr) is used for bounding purposes. The seismic CDF chosen is judged to be sufficient to support an order of magnitude LGS ILRT external events risk impact assessment.

3.4.3.6 PRA Quality Summary

Based on the above, the LGS FPIE PRA is of sufficient quality and scope for this application. The modeling is detailed: including a comprehensive set of initiating events (transients, LOCAs, and support system failures) including internal flood, system modeling, human reliability analysis and common cause evaluations. The LGS PRA technical capability evaluations and the maintenance and update processes described above provide a robust basis for concluding that these PRA models are suitable for use in the risk-informed process used for this application.

The Fire PRA Model results and the adjusted seismic CDF from the weakest link model using updated 2008 USGS Seismic Hazard Curves are judged to be adequate in performing a bounding “order of magnitude” assessment of ILRT impact.

3.4.3.7 Identification of Key Assumptions

The methodology employed in this risk assessment followed the EPRI guidance as previously approved by the NRC. The analysis included the incorporation of several sensitivity studies and factored in the potential impacts from external events in a bounding fashion. None of the sensitivity studies or bounding analyses indicated any source of uncertainty or modeling assumption that would have resulted in exceeding the acceptance guidelines. The accepted process utilizes a bounding analysis approach, mostly driven by that CDF contribution which does not already lead to LERF. Therefore, there are no key assumptions or sources of uncertainty identified for this application (i.e., those which would change the conclusions from the risk assessment results presented here).

3.4.3.8 Summary

A PRA technical adequacy evaluation was performed consistent with the requirements of RG-1.200, Revision 2 (Reference 11). This evaluation, combined with the details of the results of the analysis in Attachment 3 of this submittal demonstrates with reasonable assurance that the proposed extension to the ILRT interval for LGS, Units 1 and 2 to fifteen years satisfies the risk acceptance guidelines in RG 1.174 (Reference 10).

3.4.3.9 Conclusions

Based on the Attachment 3, Section 5 results, Section 6 sensitivity calculations, and the Appendix B DWBT analysis, the following conclusions regarding the assessment of the plant risk are associated with permanently extending the Type A ILRT and DWBT test frequency to fifteen years:

- RG 1.174 (Reference 10) provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines "very small" changes in risk as resulting in increases of CDF below 1.0E-06/yr and increases in LERF below 1.0E-07/yr. "Small" changes in risk are defined as increases in CDF below 1.0E-05/yr and increases in LERF below 1.0E-06/yr. Since the ILRT extension was demonstrated to have negligible impact on CDF for LGS, the relevant criterion is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval for the base case with corrosion included is 3.23E-08/yr. In using the EPRI Expert Elicitation methodology, the change is estimated as 3.11E-09/yr. Both of these values fall within the "very small" change region of the acceptance guidelines in RG 1.174.

- The change in dose risk for changing the Type A test frequency from three-per-ten years to once-per-fifteen-years, measured as an increase to the total integrated dose risk for all internal events accident sequences for LGS, is 6.60E-02 person-rem/yr (0.36%) using the EPRI guidance with the base case corrosion included (Table 5.6-1). The change in dose risk drops to 1.16E-02 person-rem/yr (0.06%), when using the EPRI Expert Elicitation methodology. The values calculated per the EPRI guidance are all lower than the acceptance criteria of ≤1.0 person-rem/yr or <1.0% person-rem/yr defined in Section 1.3 of Attachment 3 of this submittal.

- The increase in the conditional containment failure frequency from the three in ten-year interval to one in fifteen years, including corrosion effects using the EPRI guidance is 1.02%. This value drops to 0.10% using the EPRI Expert Elicitation methodology (see Table 6.2-2). Both of these values are below the acceptance criteria of less than 1.5% defined in Section 1.3 of Attachment 3 of this submittal.

- To determine the potential impact from external events, a bounding assessment from the risk associated with external events was performed utilizing available information. As shown in Table 5.7-4 of Attachment 3, the total increase in LERF due to internal events and the bounding external events assessment is 4.12E-07/yr. This value is in Region II of the RG 1.174 acceptance guidelines.

- As shown in Table 5.7-5 of Attachment 3, the same bounding analysis indicates that the total LERF from both internal and external risks is 2.72E-06/yr, which is less than the RG 1.174 limit of 1.0E-05/yr given that the ΔLERF is in Region II (small change in risk).

- Including age-adjusted steel liner corrosion effects in the ILRT assessment was demonstrated to be a small contributor to the impact of extending the ILRT interval for LGS.

- A DWBT risk analysis documented in Appendix B of Attachment 3 provides key metric values that, in combination with ILRT results, would not change the ILRT related conclusions described above. The DWBT values for an interval change from the original 3-in-10 years to one in 15 years are compared below to the ILRT base case with corrosion. These DWBT values are developed in Appendix B and reported in Appendix B, Section B.5.

  Delta CDF = 7.86E-10/yr (ILRT increase = 0.0)
  Delta LERF = 3.60E-09/yr (ILRT increase = 3.23E-08/yr)
  Delta Dose = 1.5E-02 p-rem/yr (ILRT increase = 6.60E-02 p-rem/yr)
  Delta CCFP = 0.003% (ILRT increase = 1.02%)

  The DWBT CDF increase is less than 0.1% of Base CDF. The DWBT values for LERF and CCFP are significantly below the ILRT values. Although the DWBT person-rem dose rate increase is about one-fourth of the ILRT dose rate increase, the total dose rate increase is still less than 0.5%, which is well less than the acceptance criteria of less than 1.0% increase.

Therefore, increasing the ILRT and DWBT intervals on a permanent basis to a one-in fifteen-year frequency is not considered to be significant since it represents only a “small” change in the LGS risk profiles.

Previous Assessments

In NUREG-1493 (Reference 13), the NRC has previously concluded the following:

- Reducing the frequency of Type A tests (ILRTs) from three per 10 years to one per 20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk is 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, increasing the interval between ILRTs is possible with minimal impact on public risk. The impact of relaxing the ILRT frequency beyond one in 20 years has not been evaluated. Beyond testing the performance of containment penetrations, ILRTs also test the integrity of the containment structure.

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

3.5 Non-Risk Based Assessment

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

3.5.1 Maintenance Rule Structures Monitoring Program

The Maintenance Rule Structures Monitoring Program provides an approach to systematically evaluate the various plant structures such that the effectiveness of a maintenance program can be evaluated. The program consists of the condition monitoring and timely repair, replacement or refurbishment or age-related or event related degradation, which will prevent continued degradation resulting in the loss of serviceability or the design function of the structure.

The development of this program consists of defining those tasks and the frequency at which they will be performed, which will ensure that timely identification, assessment, and repair, replacement or refurbishment of component degradation is accomplished. The results of the inspections will be used for trending of potential continued degradation and the need for corrective action.

The scope of this program consists of defining and performing periodic structural evaluations, which will ensure the timely identification, assessment and repair of degraded structural elements. The elements to be evaluated include the following:

- Concrete
- Structural Steel, including platforms and ladders
- Masonry Walls
- Equipment Foundations
- Roofing
- Component Supports
- Vertical and Underground Tanks
- Structural Isolation Gaps
- Watertight Doors, Flood Barriers and Flood Seals
- Building Siding
- Structural Bolting (including High Strength Structural Bolting)

The inspection program typically shows a task frequency of 5 years. For BWRs, the cognizant Structural Engineer shall be permitted to increase the frequency to 3 cycles in order to coincide with 2-year refueling cycles, for inside containment monitoring activities (and all other BWR inaccessible areas during normal plant operating conditions). This increase is subject to any regulatory commitments.

These examination frequencies do not preclude more frequent examinations if deemed necessary or less frequent examinations (with a minimum frequency of every 5 years). For those structures in which conditions or structural integrity warrant such relaxation, the program administrator may adjust based on specific plant environments, commitments or observed degradation, which dictate that an increased or other frequency is prudent. Examples of conditions dictating increased inspection frequencies are:

1. Environments which contain aggressive chemicals which could degrade concrete or steel elements,
2. Concrete elements which have been inspected and found to have active cracks,
3. Equipment vibrations which could lead to structural degradation,
4. Ladders and platforms located in high humidity areas which degradation could impact safe use.

The evaluator is responsible for determining the acceptability of a degraded element using codes, standards, industry guidelines, engineering experience, analysis and/or more detailed examinations. The evaluation should determine if the degraded element meets or exceeds all of its design basis requirements, or requires repair, maintenance, more frequent monitoring, or further evaluation to restore/ensure functional integrity.

Based upon the evaluation, a classification of the condition of the structural element should be made per the following:

- Acceptable
  Acceptable structural elements are capable of performing their structural functions, including the protection and support of systems or components. Acceptable structural elements are free of deficiencies or degradation that could lead to possible failure or have minor deficiencies that are cosmetic in nature and will have no effect on the functional integrity of the SSC.

- Acceptable with Deficiencies
  Structural elements that are acceptable with deficiencies are those which are capable of performing their structural functions, including the protection or support of systems or components, but are degraded or have deficiencies to the degree that they could eventually become detrimental to the functional performance of the SSC. Initiate an Issue Report (IR) for this classification.

- Unacceptable
  Unacceptable structural elements are those which are damaged or degraded such that they are not capable of performing their structural functions, including the protection or support of systems or components. This category also includes those elements (which are presently acceptable) that are degrading at a rate such that the element may not perform its structural function prior to the next scheduled examination. Unacceptable structural elements should be classified as a functional failure. An IR must be initiated for all such classified structural elements.

3.5.2 Service Level I Protective Coatings Program

The Service Level I Protective Coatings program provides a common approach in controlling, applying, maintaining, and periodically assessing Service Level I Coatings. Service Level I coatings are used in areas inside the LGS reactor containments where the coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown.

During walkdowns, coated surfaces are visually examined for any precursors to coating failure(s) or areas that have already failed. Precursors include:

- Chalking
- Undercutting
- Sags/Runs
- Substrate Damage (surface rust, pitting, wastage, etc.)
- Discoloration/Fading
- Erosion
- Checking
- Cracking
- Wrinkling
- Flaking/Peeling/Delamination
- Blistering
- Rusting
- Mechanical Damage

3.5.3 Containment Inservice Inspection Program

The LGS Containment ISI (CISI) Plan includes ASME Section CISI Class MC pressure retaining components and their integral attachments (including metal liner), and CISI Class CC components and structures that meet the criteria of Subarticle IWA-1300. This CISI Plan also includes information related to augmented examination areas, component accessibility, and examination review.

The LGS Second Interval Containment Inservice Inspection Program Plan was developed in accordance with the requirements of 10 CFR 50.55a and the 2001 Edition with the 2003 Addenda of ASME Section XI, subject to the limitations and modifications contained within paragraph (b) of the regulation. With the update to the ISI Program for the Fourth ISI Interval for ISI Class 1, 2, and 3 components, including their supports, the CISI Program was updated to its Third CISI Interval for ISI Class MC and CC components. This update will enable all of the ISI and CISI Program components / piping structural elements (elements) to be based on the same effective Edition and Addenda of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&VP) Code, Section XI, as well as share a common interval start and end date. The Third Interval CISI Program Plan addresses Subsections IWE and IWL, Mandatory Appendices of ASME Section XI, approved IWE Code Cases, and approved alternatives through relief requests (RRs) and SEs and utilizes the Inspection Program as defined therein. The LGS Third Interval Containment Inservice Inspection Program Plan was developed in accordance with the requirements of 10 CFR 50.55a and the 2007 Edition with the 2008 Addenda of ASME Section XI, subject to the limitations and modifications contained within paragraph (b) of the regulation. The LGS Third CISI Interval is effective from February 1, 2017, through January 31, 2027, for Units 1 and 2.

The 10 CFR 50.55a limitations and modifications are detailed below:

10 CFR 50.55a(b)(2)(viii)(E) – *Concrete Containment Examinations (Fifth Provision)*

For Class CC applications, the applicant or licensee must evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. For each inaccessible area identified, the licensee shall provide the following in the ISI Summary Report required by IWA-6000:

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

10 CFR 50.55a(b)(2)(ix)(A) – *Metal Containment Examinations (First Provision)*

For Class MC applications, the following applies to inaccessible areas.

(1) For each inaccessible area identified for evaluation, the applicant or licensee must provide the following in the ISI Summary Report as required by IWA-6000:
   i. A description of the type and estimated extent of degradation, and the conditions that lead to the degradation;
   ii. An evaluation of each area, and the result of the evaluation; and
   iii. A description of necessary corrective actions.

10 CFR 50.55a(b)(2)(ix)(B) – *Metal Containment Examinations (Second Provision)*

When performing remotely, the visual examinations required by Subsection IWE, the maximum direct examination distance specified in Table IWA-2210-1 may be extended and the minimum illumination requirements specified in Table IWA-2210-1 may be decreased provided that the conditions or indications for which the visual examination is performed can be detected at the chosen distance and illumination.

10 CFR 50.55a(b)(2)(ix)(J) – *Metal Containment Examinations (Tenth Provision)*

In general, a repair/replacement activity such as replacing a large containment penetration; cutting a large construction opening in the containment pressure boundary to replace steam generators, reactor vessel heads, pressurizers or other major equipment; or other similar modification is considered a major containment modification. When applying IWE-5000 to Class MC pressure-retaining components, any major containment modification or repair/replacement must be followed by a Type A test to provide assurance of both containment structural integrity and leak-tight integrity prior to returning to service, in accordance with 10 CFR 50, Appendix J, Option A or Option B, whichever the applicant's or licensee's Containment Leak-Rate Testing Program is based. When applying IWE-5000, if a Type A, B or C Test is performed, the test pressure and acceptance standard for the test must be in accordance with 10 CFR 50, Appendix J.

Augmented Examination Areas

The containment sections of the ISI Classification Basis Document discuss the containment design and components. Metal containment surface areas subject to accelerated degradation and aging require augmented examination per Examination Category E-C and Paragraph IWE-1240.

Similarly, concrete surfaces may be subject to detailed visual examination in accordance with item number L1.12 and paragraph IWL-2310(b), if declared to be 'Suspect Areas'.

No significant conditions were found in the First CISI Interval; however, significant conditions were identified in the Second CISI Interval, requiring application of additional augmented examination requirements under paragraph IWE-1240 or IWL-2310. During the Second CISI Interval, containment surface areas were identified by LGS and were designated as Examination Category E-C, per paragraph IWE-1240. The submerged portion of the suppression pool is required to receive a Subsection IWE examination during each ISI period not to exceed a maximum interval of 4 years (two refueling cycles).

As a result of license renewal, the ASME Section XI, Subsection IWE aging management program was enhanced to:

1. Manage the suppression pool liner and coating system to:

    a. Remove any accumulated sludge in the suppression pool every RFO.

    b. Perform an ASME IWE examination of the submerged portion of the suppression pool each ISI period (not to exceed 4 years between examinations).

    c. Use the results of the ASME IWE Examination to implement a coating maintenance plan to perform the following, *prior* to the period of extended operation (Unit 1: 10/26/2024; Unit 2: 6/22/2029).

        i. Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 50 mils plate thickness will be recoated in the outage they are identified. This plate thickness loss criterion for local areas will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

        ii. Areas of general corrosion greater than 25 mils average plate thickness loss will be recoated based on ranking of the affected surface area, high to low. This plate thickness loss criterion for areas of general corrosion will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

iii. For plates with greater than 25 percent coating depletion, the affected area will be recoated based on ranking of affected surface area depleted and metal thickness loss.

d. Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following, *during* the period of extended operation:

i. Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 50 mils plate thickness loss will be recoated in the outage they are identified. This plate thickness loss criterion for local areas will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

ii. Areas of general corrosion greater than 25 mils average plate thickness loss will be recoated in the outage they are identified. This plate thickness loss criterion for areas of general corrosion will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

2. Use the results of ASME IWE inspection of the submerged portions of the suppression pool downcomers to perform the following:

   a. Local areas (less than or equal to 5.5 inches in any direction) that have 40 mils or more metal loss will be recoated. This downcomer metal thickness loss criteria for local areas will also be used to determine when the submerged portions of the downcomers require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

   b. Areas of general corrosion (greater than 5.5 inches in any direction) that have 30 mils or more metal thickness loss will be recoated. This downcomer metal thickness loss criteria for areas of general corrosion will also be used to determine when the submerged portions of the downcomers require augmented inspections in accordance with ASME Section XI, Subsection IWE, Category E-C.

   c. The downcomer recoat and augmented inspection criteria will be implemented prior to the receipt of the renewed licenses.

3. When IWE examinations are conducted, perform ultrasonic thickness measurements on four areas of submerged suppression pool liner affected by general corrosion. The ultrasonic thickness measurement requirements will be implemented prior to receipt of the renewed licenses.

4. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting.

Augmented Examination Program AUG-32

This program augments the requirements in ASME Code, Section XI, by implementing examinations at an increased frequency or requiring additional examinations.

1. The following examinations are required as part of the AUG-32 program as required by license renewal commitment 2701321-70: Remove any accumulated sludge in the suppression pool every RFO.

2. Perform an ASME IWE examination of the submerged portion of the suppression pool each ISI period (not to exceed 4 years between examinations).

3. When IWE examinations are conducted, perform ultrasonic thickness measurements on four areas of submerged suppression pool liner affected by general corrosion.

The examinations are listed in Tables 3.5.3-1 and 3.5.3-2 below for LGS, Units 1 and 2, respectively.

Examination Results

The ASME IWE examination of the submerged portion of the suppression pool shall be conducted in accordance with ASME Section XI, Subsection IWE. The results of the ASME Section XI, IWE examination will be used to determine when recoating of the suppression pool liner or downcomers is necessary. The results of the ASME Section XI, IWE examination will also be used to determine when the suppression pool liner or downcomers require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

Components included in the containment CISI Augmented Program:

Table 3.5.3-1 – Unit 1 Components included in the AUG-32 Program					
Unit	**ASME Category**	**ASME Item**	**Comp ID**	**Description**	**Notes**
1	E-A	E1.12	10S199-SPL-SS	Suppression Pool Liner Submerged Space	Examination required each period per LR commitment
1	E-A	E1.12	10S199-VS-SPSS	Vent System Suppression Pool Submerged Space	Examination required each period per LR commitment
1	AUG	32	10S199-SPL UT	Suppression Pool Liner UT thickness per T04743	Performed each period during IWE examination
1	AUG	32	10S199-SPL Pit Grids	Suppression Pool Liner Pit Grid Measurements	Performed each period during IWE examination
1	E-C	E4.11	1-FP-01A	Floor plate > 25 mils metal loss	Classified E-C following 1R14 (2012)
1	E-C	E4.11	1-FP-04A	Floor plate > 25 mils metal loss	Classified E-C following 1R14
1	E-C	E4.11	1-FP-01B	Floor plate > 25 mils metal loss and pits > 50 mils	Classified E-C following 1R14
1	E-C	E4.11	1-FP-01C	Floor plate with pits > 50 mils	Classified E-C following 1R14
1	E-C	E4.11	1-FP-05C	Floor plate with pits > 50 mils	Classified E-C following 1R14
1	E-C	E4.11	1-FP-06C	Floor plate > 25 mils metal loss and pits > 50 mils	Classified E-C following 1R14
1	E-C	E4.11	1-FP-07C	Floor plate > 25 mils metal loss and pits > 50 mils	Classified E-C following 1R14
1	E-C	E4.11	1-FP-03D	Floor plate with pits > 50 mils	Classified E-C following 1R14
1	E-C	E4.11	1-FP-05D	Floor plate with pits > 50 mils	Classified E-C following 1R14
1	E-C	E4.11	1-WP-04A	Wall plate with pits > 50 mils	Classified E-C following 1R14
1	E-C	E4.11	1-WP-06B	Wall plate > 25 mils metal loss	Classified E-C following 1R14

Table 3.5.3-1 – Unit 1 Components included in the AUG-32 Program					
Unit	**ASME Category**	**ASME Item**	**Comp ID**	**Description**	**Notes**
1	E-C	E4.11	1-WP-07B	Wall plate > 25 mils metal loss	Classified E-C following 1R14
1	E-C	E4.11	1-WP-02A	Wall plate with pits > 50 mils	Classified E-C following 1R15 (2014)
1	E-C	E4.11	1-FP-02A	Floor plate > 25 mils metal loss (GC) and > 50 mils spot corrosion	Classified E-C following 1R16 (2016)
1	E-C	E4.11	1-FP-03A	Floor plate > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-06A	Floor plate > 25 mils metal loss (GC) and > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-10A	Floor plate with > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-11A	Floor plate > 25 mils metal loss (GC) and > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-02B	Floor plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-FP-03B	Floor plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-FP-04B	Floor plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-FP-05B	Floor plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-FP-06B	Floor plate > 25 mils metal loss (GC) and > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-07B	Floor plate > 25 mils metal loss (GC) and > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-08B	Floor plate with > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-09B	Floor plate > 25 mils metal loss (GC)	Classified E-C following 1R16

Table 3.5.3-1 – Unit 1 Components included in the AUG-32 Program

Unit	ASME Category	ASME Item	Comp ID	Description	Notes
1	E-C	E4.11	1-FP-10B	Floor plate > 25 mils metal loss (GC) and > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-02C	Floor plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-FP-03C	Floor plate > 25 mils metal loss (GC) and > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-04C	Floor plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-FP-08C	Floor plate with > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-09C	Floor plate with > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-01D	Floor plate with > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-02D	Floor plate > 25 mils metal loss (GC) and > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-FP-04D	Floor plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-FP-08D	Floor plate with > 50 mils spot corrosion	Classified E-C following 1R16
1	E-C	E4.11	1-WP-01A	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-03A	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-05A	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-06A	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-09A	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-10A	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-01B	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16

Table 3.5.3-1 – Unit 1 Components included in the AUG-32 Program					
Unit	**ASME Category**	**ASME Item**	**Comp ID**	**Description**	**Notes**
1	E-C	E4.11	1-WP-02B	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-04B	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-05B	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-09B	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-10B	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-02C	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-04C	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-05C	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-06C	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-WP-10C	Wall plate > 25 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-DC-44	Downcomer > 30 mils metal loss (GC)	Classified E-C following 1R16
1	E-C	E4.11	1-DC-48	Downcomer > 30 mils metal loss (GC)	Classified E-C following 1R16

Table 3.5.3-2 – Unit 2 Components Included in the AUG-32 Program					
Unit	**ASME Category**	**ASME Item**	**Comp ID**	**Description**	**Notes**
2	E-A	E1.12	20S199-SPL-SS	Suppression Pool Liner Submerged Space	Examination required each period per LR commitment
2	E-A	E1.12	20S199-VS-SPSS	Vent System Suppression Pool Submerged Space	Examination required each period per LR commitment
2	AUG	32	20S199-SPL-UT	Suppression Pool Liner thickness per T04743	Performed each period during IWE examination

Table 3.5.3-2 – Unit 2 Components Included in the AUG-32 Program					
Unit	**ASME Category**	**ASME Item**	**Comp ID**	**Description**	**Notes**
2	AUG	32	20S199-SPL Pit Grids	Suppression Pool Liner Pit Grid Measurements	Performed each period during IWE examination
2	E-C	E4.11	2-FP-02A	Floor plate with pits > 50 mils	Classified E-C following 2R12 (2013)
2	E-C	E4.11	2-FP-05A	Floor plate with pits > 50 mils	Classified E-C following 2R12
2	E-C	E4.11	2-FP-06A	Floor plate > 25 mils general material loss	Classified E-C following 2R12
2	E-C	E4.11	2-FP-09A	Floor plate > 25 mils general material loss	Classified E-C following 2R12
2	E-C	E4.11	2-FP-01E	Floor plate with pits > 50 mils	Classified E-C following 2R14 (2017)
2	E-C	E4.11	2-FP-02B	Floor plate with pits > 50 mils	Classified E-C following 2R14
2	E-C	E4.11	2-FP-03A	Floor plate > 25 mils general material loss	Classified E-C following 2R14
2	E-C	E4.11	2-FP-04A	Floor plate > 25 mils general material loss	Classified E-C following 2R14
2	E-C	E4.11	2-FP-05B	Floor plate > 25 mils general material loss	Classified E-C following 2R14
2	E-C	E4.11	2-FP-07A	Floor plate > 25 mils general material loss	Classified E-C following 2R14
2	E-C	E4.11	2-FP-09C	Floor plate with pits > 50 mils	Classified E-C following 2R14
2	E-C	E4.11	2-FP-10A	Floor plate with pits > 50 mils	Classified E-C following 2R14
2	E-C	E4.11	2-FP-10B	Floor plate with pits > 50 mils	Classified E-C following 2R14

Table 3.5.3-2 – Unit 2 Components Included in the AUG-32 Program					
Unit	**ASME Category**	**ASME Item**	**Comp ID**	**Description**	**Notes**
2	E-C	E4.11	2-FP-11A	Floor plate > 25 mils general material loss	Classified E-C following 2R14

Component Accessibility

ISI Class MC and CC components subject to examination shall remain accessible for either direct or remote visual examination, from at least one side, per the requirements of ASME Section XI, Paragraph IWE-1230.

Paragraph IWE-1231(a)(3) requires 80% of the pressure-retaining boundary that was accessible after construction to remain accessible for either direct or remote visual examination, from at least one side of the vessel, for the life of the plant.

Portions of components embedded in concrete or otherwise made inaccessible during construction are exempted from examination, provided that the requirements of ASME Section XI, Paragraph IWE-1232 have been fully satisfied.

In addition, inaccessible surface areas exempted from examination include those surface areas where visual access by line of sight with adequate lighting from permanent vantage points is obstructed by permanent plant structures, equipment, or components; provided these surface areas do not require examination in accordance with the inspection plan, or augmented examination in accordance with paragraph IWE-1240.

Responsible Individual and Engineer

ASME Section XI Subsection IWE requires the Responsible Individual to be involved in the development, performance, and review of the CISI examinations. The Responsible Individual shall meet the requirements of ASME Section XI, Paragraph IWE-2320.

ASME Section XI Subsection IWL requires the Responsible Engineer to be involved in the development, approval, and review of the CISI examinations. The Responsible Engineer shall meet the requirements of ASME Section XI, Paragraph IWL-2320.

Inspection Frequency

ASME Section XI, Subsection IWE, Item Number E1.12 requires wetted surfaces of the submerged areas to be inspected once per interval and the inspections can be deferred until the end of the interval. ASME Section XI, Subsection IWE, Item Number E4.11 requires visible surfaces to be inspected once per period. Per the License Renewal Commitment, the inspections performed for Item Numbers E1.12 and E4.11 (the submerged portion of the suppression pool) must be completed once per period not to exceed a maximum interval of 4 years (two RFOs).

Class MC Component Examinations:

Unit 1 **Examination Category (with Examination Category Description)**	**Item Number**	**Description**	**Exam Requirements**	**Total Number of Components**
E-A Containment Surfaces	E1.11	Containment Vessel Pressure Retaining Boundary - Accessible Surface Areas	General Visual	24
	E1.12	Containment Vessel Pressure Retaining Boundary - Wetted Surfaces of Submerged Areas	Visual, VT-3	1
	E1.20	Containment Vessel Pressure Retaining Boundary - BWR Vent System Accessible Surface Area	Visual, VT-3	11
E-C Containment Surfaces Requiring Augmented Examination	E4.11	Containment Surface Areas - Visible Surfaces	Visual, VT-1	53
	E4.12	Containment Surface Areas - Surface Area Grid Minimum Wall Thickness Location	Volumetric (Ultrasonic Thickness)	0
E-G Pressure Retaining Bolting	E8.10	Bolted Connections	Visual, VT-1	19

Unit 2 Examination Category (with Examination Category Description)	Item Number	Description	Exam Requirements	Total Number of Components
E-A Containment Surfaces	E1.11	Containment Vessel Pressure Retaining Boundary - Accessible Surface Areas	General Visual	24
	E1.12	Containment Vessel Pressure Retaining Boundary - Wetted Surfaces of Submerged Areas	Visual, VT-3	1
	E1.20	Containment Vessel Pressure Retaining Boundary - BWR Vent System Accessible Surface Area	Visual, VT-3	11
E-C Containment Surfaces Requiring Augmented Examination	E4.11	Containment Surface Areas - Visible Surfaces	Visual, VT-1	14
	E4.12	Containment Surface Areas - Surface Area Grid Minimum Wall Thickness Location	Volumetric (Ultrasonic Thickness)	0
E-G Pressure Retaining Bolting	E8.10	Bolted Connections	Visual, VT-1	19

Table 3.5.3-5 – Units 1 and 2 Third CISI Interval/Period/Outage Matrix (Class MC Components)						
Unit 1		**Unit 1 Period**	**Interval**	**Unit 2 Period**	**Unit 2**	
Outage Number	**Projected Outage Start Date or Outage Duration**	**Start Date to End Date**		**Start Date to End Date**	**Projected Outage Start Date or Outage Duration**	**Outage Number**
Li1R17	Completed Spring 2018	1st 2/1/17 to 1/31/21	3rd (Unit 1) 2/1/17 to 1/31/27[1]	1st 2/1/17 to 1/31/20	Completed Spring 2017	Li2R14
Li1R18	Scheduled Spring 2020				Scheduled Spring 2019	Li2R15
Li1R19	Scheduled Spring 2022	2nd 2/1/21 to 1/31/24		2nd 2/1/20 to 1/31/23	Scheduled Spring 2021	Li2R16
Li1R20	Scheduled Spring 2024	3rd 2/1/24 to 1/31/27	3rd (Unit 2) 2/1/17 to 1/31/27[2]	3rd 2/1/23 to 1/31/27	Scheduled Spring 2023	Li2R17
Li1R21	Scheduled Spring 2026				Scheduled Spring 2025	Li2R18

Note 1: The LGS, Unit 1 Common Second Period was reduced by one year and the First Period was extended by one year as permitted by Paragraph IWA-2430(c)(3) in order to match the RFO schedule (2-1-2) for both units.

Note 2: The LGS, Unit 2 Second Period was reduced by one year and the Third Period was extended by one year as permitted by Paragraph IWA-2430(c)(3) in order to match the RFO schedule (2-1-2) for both units.

Class CC Component Examinations:

Table 3.5.3-6 – Units 1 and 2 Third CISI Interval/Period/Outage Matrix (Class CC Components)

Unit 1		**5-Year Period**	**Interval**	**5-Year Period**	**Unit 2**	
Outage Number	**Projected Outage Start Date or Outage Duration**	**Start Date to End Date**		**Start Date to End Date**	**Projected Outage Start Date or Outage Duration**	**Outage Number**
Li1R17	Completed Spring 2018	1st 2/1/17 to 1/31/22		1st 2/1/17 to 1/31/22	Completed Spring 2017	Li2R14
Li1R18	Scheduled Spring 2020				Scheduled Spring 2019	Li2R15
Li1R19	Scheduled Spring 2022	2nd 2/1/22 to 1/31/27	3rd (Unit 1) 2/1/17 to 1/31/27[1]		Scheduled Spring 2021	Li2R16
Li1R20	Scheduled Spring 2024			3rd 2/1/22 to 1/31/27	Scheduled Spring 2023	Li2R17
Li1R21	Scheduled Spring 2026		3rd (Unit 2) 2/1/17 to 1/31/27[1]		Scheduled Spring 2025	Li2R18

Note 1: The Subsection IWL inspection schedule for the CC surface meets the requirements of subarticle IWL-2400. Paragraph IWL-2510 surface inspections will be performed once every 5 years. They will begin not more than 1 year prior to the specified date and will be completed not more than 1 year after such date. 10 CFR 50.55a required that the initial baseline CISIs for each unit be completed between September 9, 1996, and September 8, 2001. The rolling inspection period date and associated 2-year window for each unit is determined from these first baseline CISI inspection dates (4/00 (Li1R08) and 4/01 (Li2R06) for Units 1 and 2, respectively).

Table 3.5.3-7 – LGS, Unit 1 CISI IWE Inspection Summary				
Examination Category (with Examination Category Description)	**Item Number**	**Description**	**Exam Requirements**	**Total Number of Components**
L-A Concrete	L1.11	Concrete Surfaces - All Accessible Surface Areas	General Visual	3
	L1.12	Concrete Surfaces - Suspect Areas	Detailed Visual	0

3.5.3-8 – Table LGS, Unit 2 CISI IWE Inspection Summary				
Examination Category (with Examination Category Description)	**Item Number**	**Description**	**Exam Requirements**	**Total Number of Components**
L-A Concrete	L1.11	Concrete Surfaces - All Accessible Surface Areas	General Visual	3
	L1.12	Concrete Surfaces - Suspect Areas	Detailed Visual	0

3.5.4 Supplemental Inspection Requirements

With the implementation of the proposed change, Units 1 and 2 TS 6.8.4.g will be revised by replacing the reference to RG 1.163 (Reference 4) with reference to NEI 94-01, Revision 3-A (Reference 1). This will require that a general visual examination of accessible interior and exterior surfaces of the containment for structural deterioration that may affect the containment leak-tight integrity be conducted. This inspection must be conducted prior to each Type A test and during at least three other outages before the next Type A test, if the interval for the Type A test has been extended to 15 years in accordance with the following sections of NEI 94-01, Revision 3-A:

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

In addition to the IWE and IWL examinations scheduled in accordance with the Containment Inservice Inspection Program, the performance of inspections in accordance with the Maintenance Rule Structures Monitoring Program (Reference Section 3.5.1 of this submittal) will be utilized to ensure compliance with the visual inspection requirements of TS SR 4.6.1.5.1 and NEI 94-01, Revision 3-A.

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

LGS Types B and C testing program requires testing of electrical penetrations, airlocks, hatches, flanges, and containment isolation valves (CIVs) in accordance with 10 CFR Part 50, Appendix J, Option B, and RG 1.163. The results of the test program are used to demonstrate that proper maintenance and repairs are made on these components throughout their service life. The Types B and C testing program provides a means to protect the health and safety of plant personnel and the public by maintaining leakage from these components below appropriate limits. In accordance with the Units 1 and 2 TS 6.8.4.g, the containment leakage rate, as determined by totaling the leakages of all Type B and Type C LLRTs (exclusive of the main steam lines and personnel access door seals), must be less than or equal to 0.6 L_a, which equals 94,964 standard cubic centimeters per minute (sccm) where L_a is approximately 158,273.

As discussed in NUREG-1493 (Reference 13), Type B and Type C tests can identify the vast majority of all potential containment leakage paths. Type B and Type C testing will continue to provide a high degree of assurance that containment integrity is maintained.

A review of the As-Found (AF) / As-Left (AL) test values for LGS, Units 1 and 2 can be summarized as:

- LGS, Unit 1 AF minimum pathway leak rate shows an average of 36.34% of 0.6La with a high of 52.59% of 0.6La

- LGS, Unit 1 AL maximum pathway leak rate shows an average of 58.07% of 0.6La with a high of 68.31% of 0.6La.

- LGS, Unit 2 AF minimum pathway leak rate shows an average of 23.25% of 0.6La with a high of 31.55% of 0.6La.
- LGS, Unit 2 AL maximum pathway leak rate shows an average of 42.23% of 0.6La with a high of 51.87% of 0.6La.

Tables 3.5.5-1 and 3.5.5-2 below provide the LLRT data trend summaries for LGS, Units 1 and 2, respectively, since 2007. These summaries demonstrate a history of satisfactory Types B and C tested component performance from 2008 through 2018 for LGS, Unit 1 and from 2007 through 2017 for Unit 2.

Table 3.5.5-1 – LGS, Unit 1 Types B and C LLRT Combined As-Found/As-Left Trend Summary

RFO / Year	2008	2010	2012	2014	2016	2018
	Li1R12	**Li1R13**	**Li1R14**	**Li1R15**	**Li1R16**	**LiR17**
AF Min Path (sccm)	22094	49940	43636	35291	24434	31668
Fraction of 0.6 La (percent)	23.27	52.59	45.95	37.16	25.73	33.35
AL Max Path (sccm)	64868	50821	61456	58417	48578	46743
Fraction of 0.6 La (percent)	68.31	53.52	64.72	61.51	51.15	49.22
AL Min Path (sccm)	40435	23305	31976	34690	24434	23727
Fraction of 0.6 La (percent)	42.58	24.54	33.67	36.53	25.73	24.99

Table 3.5.5-2 – LGS, Unit 2 Types B and C LLRT Combined As-Found/As-Left Trend Summary						
RFO / Year	**2007**	**2009**	**2011**	**2013**	**2015**	**2017**
	Li2R09	**Li2R10**	**Li2R11**	**Li2R12**	**Li2R13**	**Li2R14**
AF Min Path (sccm)	18429	18492	20627	20920	29958	24050
Fraction of 0.6 La (percent)	19.41	19.47	21.72	22.03	31.55	25.33
AL Max Path (sccm)	36692	36213	35684	49255	43414	39323
Fraction of 0.6 La (percent)	38.64	38.13	37.58	51.87	45.72	41.41
AL Min Path (sccm)	17127	14987	14063	20813	23734	16131
Fraction of 0.6 La (percent)	18.04	15.78	14.81	21.92	24.99	16.99

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

Tables 3.5.5-3 and 3.5.5-4 below identify the components that were on extended LLRT intervals and have not demonstrated acceptable performance during the previous two outages for LGS, Units 1 and 2:

Table 3.5.5-3 – LGS, Unit 1 Types B and C LLRT Program Implementation Review						
Li1R16 - 2016						
Component	**As-Found sccm**	**Admin Limit sccm**	**As-Left sccm**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval**
Note 1						
Li1R17 - 2018						
Component	**As-Found sccm**	**Admin Limit sccm**	**As-Left sccm**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval**
015-1139	15,100	2000	263	Note 2	Note 2	30 Months

Note 1: There were no administrative limit failures associated with components on extended intervals identified in Li1R16.

Note 2: CIV 015-1139 is a 3-inch gate valve. Cause of failure was determined to be approximately 1 inch of metal and rust debris in the bottom of the valve body. This material was suspected to have originated from the carbon steel service air to containment piping. Corrective actions included disassembly and overhaul of valve. The valve was cleaned, lapped and the wedge was skim cut. Following maintenance, a blue check was performed with satisfactory results.

Table 3.5.5-4 – LGS, Unit 2 Types B and C LLRT Program Implementation Review						
Li2R13 - 2015						
Component	**As-Found sccm**	**Admin Limit sccm**	**As-Left sccm**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval**
XV-059-241A	3740	1000	1000	Note 3	Replaced Ball Valve	30 Months
Li2R14 - 2017						
Component	**As-Found sccm**	**Admin Limit sccm**	**As-Left sccm**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval**
059-2005A	4330	600	4330	Note 4	Note 4	30 Months
SV-057-241 SV-057-284	1080	1000	1080	Note 5	Note 5	30 Months

Note 3: Normal age related degradation.

Note 4: The observed leakage of 059-2005A during Li2R14 was evaluated and determined to not have a significant impact on overall containment leakage. Minimum pathway leakage was measured at 166 SCCM through outboard containment isolation valve HV-059-229A. Work order is planned for Li2R15 (April 2019) to rework valve internals and understand cause of failure.

Note 5: The observed leakage of SV-057-241 and SV-057-284 during Li2R14 was evaluated and determined to not have a significant impact on overall containment leakage. Minimum pathway was measured at 72 SCCM through inboard containment isolation valve SV-057-281. Work order is planned for Li2R15 (April 2019) to rework valve internals and understand cause of failure.

3.6 Operating Experience (OE)

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

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

- Information Notice (IN) 92-20, "Inadequate Local Leak Rate Testing"

- IN 2004-09, "Corrosion of Steel Containment and Containment Liner"
- IN 2010-12, "Containment Liner Corrosion"
- IN 2014-07, "Degradation of Leak Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner"
- Regulatory Issue Summary (RIS) 2016-07, "Containment Shell or Liner Moisture Barrier Inspection"

Each of these areas is discussed in detail in Sections 3.6.1 through 3.6.5, respectively.

3.6.1 IN 92-20, Inadequate Local Leak Rate Testing

The NRC issued IN 92-20 to alert licensees of problems with local leak rate testing two-ply stainless steel bellows used on piping penetrations at four different plants: Quad Cities Nuclear Power Station, Dresden Nuclear Station, Perry Nuclear Power Plant and the Clinton Station. Specifically, LLRTs could not be relied upon to accurately measure the leakage rate that would occur under accident conditions since, during testing, the two plies in the bellows were in contact with each other, restricting the flow of the test medium to the crack locations. Any two-ply bellows of similar construction may be susceptible to this problem. The common issue in the four events was the failure to adequately perform local leak rate testing on different penetration configurations leading to problems that were discovered during ILRT tests in the first three cases.

In the event at Quad Cities, the two-ply bellows design was not properly subjected to LLRT pressure and the conclusion of the utility was that the two-ply bellows design could not be Type B LLRT tested as configured.

In the events at both Dresden and Perry, flanges were not considered to be a leakage path when the Type C LLRT test was designed. This omission led to a leakage path that was not discovered until the plant performed an ILRT test.

In the event at Clinton, relief valve discharge lines that were assumed to terminate below the suppression pool minimum drawdown level were discovered to terminate at a level above that datum. These lines needed to be reconfigured, and the valves should have been Type C LLRT tested.

Discussion:

IN 1992-20 was reviewed and determined to not apply at LGS. The arrangement described in the Notice does not exist at LGS. There are no bellows in the primary containment tested boundaries, and flanges are tested via a double O-ring flanged design, which ensures proper testing of flanged connections.

3.6.2 IN 2004-09, Corrosion of Steel Containment and Containment Liner

The NRC issued IN 2004-09 to alert addressees to occurrences of corrosion in freestanding metallic containments and in 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 and may reduce the design margin of safety against postulated accident and environmental loads. Experience has shown that the integrity of the moisture barrier seal at the floor-to-liner or floor-to-containment junctions 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:

LGS performs periodic inspections of the primary containment's Class MC pressure-retaining components and their integral attachments, and of metallic shells and penetration lines of Class CC pressure-retaining components and their integral attachments, per the requirements of 10 CFR 50.55a. The events described in IN 2004-09 have not been found during any of the recent LGS containment liner inspections.

3.6.3 IN 2010-12, "Containment Liner Corrosion"

IN 2010-12 was issued to alert plant operators to three events that occurred where the steel liner of the containment building was corroded and degraded. At the Beaver Valley and Brunswick plants, material had been found in the concrete, which trapped moisture against the liner plate and corroded the steel. In one case, it was material intentionally placed in the building and in the other case, it was foreign material, which had inadvertently been left in the form when the wall was poured. But the result in both cases was that the material trapped moisture against the steel liner plate leading to corrosion. In the third case, Salem, an insulating material placed between the concrete floor and the steel liner plate absorbed moisture and led to corrosion of the liner plate.

Discussion:

All Exelon stations, including LGS, have implemented periodic examinations during refueling outages on metallic containment structures or liners in accordance with ASME Section XI, Subsection IWE. The applicable Exelon visual examination procedure, ER-AA-335-018, requires the conditions described in the IN examples to be recorded. Conditions that may affect containment integrity are then required to be evaluated by either supplemental examination (e.g., VT-1, UT), engineering evaluation, and/or repair/replacement prior to startup from the refueling outage. Rigorously implementing the examinations and tests in accordance with the requirements of ASME IWE and Appendix J and dispositioning observed conditions in accordance with Code-established acceptance criteria are existing barriers that ensure the integrity of metallic containment surfaces and liners is maintained.

3.6.4 IN 2014-07, Degradation of Leak Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner

The NRC issued IN 2014-07 to inform the industry of issues concerning degradation of floor weld leak-chase channel systems of steel containment shell and concrete containment metallic liner that could affect leak-tightness and aging management of containment structures. Specifically, this IN provides examples of OE at some plants of water accumulation and corrosion degradation in the leak-chase channel system that has the potential to affect the leak-tight integrity of the containment shell or liner plate. In each of the examples, the plant had no provisions in its ISI plan to inspect any portion of the leak-chase channel system for evidence of moisture intrusion and degradation of the containment metallic shell or liner within it. Therefore, these cases involved the failure to perform required visual examinations of the containment shell or liner plate leak-chase system in accordance with the ASME Code Section XI, Subsection IWE, as required by 10 CFR 50.55a(g)(4).

The containment basemat metallic shell and liner plate seam welds of pressurized water reactors are embedded in a 3 ft by 4 ft 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 while 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 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 with cylindrical shell or liner to a certain height above the floor.

Discussion:

The LGS CISI Program was reviewed and found to be in compliance with regard to classification of the suppression pool leak chases. Note 3 in Table IWE-2500-1 identifies that "examination shall include moisture barrier materials which are not seal welded." Therefore, since the LGS leak chase channels and test connections were capped and seal welded to prevent moisture intrusion, they are not in the scope of the "moisture barrier" inspections under Examination Category E-A, Item No. E1.30.

In addition, since the leak chase channels are non-structural attachment welds defined in ASME Section III, Subsection NE-4335, they are exempt from the requirements of Exam Category E-A, Item No. E1.12 (Wetted Surfaces), per Note 1(b) of Table IWE-2500-1.

Finally, the leak chase system that is installed at both LGS units does not fulfill any part of the containment pressure-retaining function, and is therefore not part of the ASME Section XI, IWE Program per IWE-1110. However, the leak chase systems do cover part of the liner plates and welds that are in the IWE Program and do serve as the containment pressure-retaining boundary; thereby, making these areas inaccessible to inspection.

As a result, the corporate containment program procedure and the containment inspection procedure were revised to identify degradation of these leak chases. These procedure revisions provide assurance that the inaccessible regions that are in the program do not degrade or at least receive an assessment, if degradation were to be discovered.

Also, as an enhancement to the CISI Program, containment liner inspection procedures were revised to identify areas under the leak chases, which are part of the “inaccessible area” that would require assessment should degradation be identified in the “accessible portion” of the suppression pool.

3.6.5 NRC RIS 2016-07, "Containment Shell or Liner Moisture Barrier Inspection"

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, "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 barriers, 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:

LGS does not have moisture barrier material as described in ASME Section XI, Table IWE-2500-1, Item E1.30. LGS, Units 1 and 2 have Mark II containments, which consist of reinforced concrete containment with a steel liner. The drywell floor (diaphragm slab) to containment wall is designed with a construction joint such that no gap exists at this location and, therefore, no moisture barrier material is required.

3.6.6 Major Containment Modifications – NRC Order EA-13-109

On June 6, 2013, the NRC issued Order EA-13-109, "Issuance of Order to Modify Licenses with Regard to Reliable Hardened Containment Vents Capable of Operation Under Severe Accident Conditions.” (Reference 26) The Order required BWRs with Mark I and Mark II containments to take certain actions to ensure that these facilities have a hardened containment vent system (HCVS) to remove decay heat from the containment, and maintain control of containment pressure within acceptable limits following events that result in loss of active containment heat removal capability while maintaining the capability to operate under severe accident (SA) conditions resulting from an Extended Loss of AC Power (ELAP).

The Order requirements are applied in a phased approach where:

- "Phase 1 involves upgrading the venting capabilities from the containment wetwell to provide reliable, severe accident capable hardened vents to assist in preventing core damage and, if necessary, to provide venting capability during severe accident conditions". (Completed "no later than startup from the second refueling outage that begins after June 30, 2014, or June 30, 2018, whichever comes first.") These modifications make changes to the LGS Containment Leakage Rate Testing Program and are described below.

- "Phase 2 involves providing additional protections for severe accident conditions through installation of a reliable, severe accident capable drywell vent system or the development of a reliable containment venting strategy that makes it unlikely that a licensee would need to vent from the containment drywell during severe accident conditions." (Completed "no later than startup from the first refueling outage that begins after June 30, 2017, or June 30, 2019, whichever comes first.") Phase 2 actions do not involve the LGS, Units 1 and 2 containment structure or Containment Leakage Rate Testing Program; therefore, Phase 2 actions are not discussed further in this LAR.

As a result of the NRC Order, the following plant modifications were made:

During 2R14 (2017) and 1R17 (2018), a hardened containment vent was installed on both Units 1 and 2.

On Unit 1, this involved conversion of an existing 20” spare penetration to a vent line to support FLEX strategy for a beyond DBA event. Outside containment, the welded cap was removed and a double O-ring flange was welded in its place. This penetration line outboard containment was then flanged to a 20” pipe containing a 12” reducer and terminating in a second double O-ring flange. Continuing outboard of containment and attached to this second double O-ring flange, two 12” air operated butterfly valves were installed in series with a ¾” test line and valve located between them.

On Unit 2, an existing 24” blind flange outside of containment connected to piping that penetrates containment and terminates in the air space above the suppression pool, was used to establish a vent line to support FLEX strategy for a beyond DBA event. The blind flange was replaced with a testable double O-ring flange. A 24” tee with a spare testable double O-ring flange was then connected. The third leg of the tee was welded to 24” pipe containing a 12” reducer and terminating in a second double O-ring flange. Continuing outboard of containment and attached to this second double O-ring flange, two 12” air operated butterfly valves were installed in series with a ¾” test line and valve located between them.

This hardened vent installation will enable plant personnel to vent containment remotely from outside containment in the event of a beyond design basis accident while maintaining double isolation capability for Penetrations X-201B (Unit 1) and X-201A (Unit 2). Following completion of this modification during the 2R14 and 1R17 RFOs in 2017 and 2018, respectively, Penetrations X-201B (Unit 1) and X-201A (Unit 2) were both leak rate tested in accordance with 10 CFR 50, Appendix J testing requirements. Both of the butterfly valves were pressurized from the test tap located between them. The double O-ring flanges between containment and the inboard butterfly valve were also tested to ensure pressure boundary integrity in these leak pathways. The leak rate of the butterfly valves was added to the leak rate of the double O-ring flanges to determine both MNPLR and MXPLR for Penetrations X-201B and X-201A. Both MNPLR and MXPLR leak rates for this penetration on Units 1 and 2 were well below 200 sccm. This leakage, when added to the Types B and C summations for both units has an insignificant impact on the leak rate margin available as compared to the leakage limit of 0.6 L_a for the total Types B and C leakage.

3.6.7 Primary Containment OE Since Completion of Last ILRTs

Service Level I Protective Coatings Program

The majority of the deficiencies discovered related to the Service Level I protective coatings have been identified and dispositioned in the containment ISI reports. The following items were technical evaluations found outside of the containment ISI examinations.

Unit 1 1R15 RFO – Spring 2014

The LGS coatings engineer performed a walkdown in 1R15 to re-assess the condition of the drywell head coating, as previously identified in the 1R14 walkdown. The walkdown confirmed that the drywell bolting support (between No. 51 and No. 52) shows apparent impact damage at the top edge. Also, light coating degradation (mechanical damage) between all of the bolts and various areas around the drywell head exterior surfaces were confirmed. Lastly, light surface corrosion was observed on the interior surfaces of the drywell head. A technical evaluation justified the as-found condition of the drywell head interior and exterior surfaces for continued service until repairs are performed in 2016.

Based on the 1R15 walkdown, the exterior surface impact damage (mechanical) between bolt supports No. 51 and No. 52 appears no different from that identified during 1R14. The impact length, width and depth are: 2.5 inches, 0.25 inches and 0.06 inches respectively. No other impacts were identified around the other bolt supports. This issue was brought to the attention of the containment ISI engineer regarding acceptance criteria of coating damage. The acceptance criteria stated for the drywell head localized area of corrosion shall not exceed 50 mils. The depth of the “wall loss” of 60 mils, exceeds the acceptance criteria stated for the drywell head. The coatings procedure states, “Documented indications exceeding the allowable criteria shall be reported to engineering for final evaluation and disposition.”

Based on discussion and concurrence by LGS containment ISI engineer, engineering determined the mechanical damage between bolt support No. 51 and No. 52 was acceptable for the following reasons:

- An evaluation was performed in Li1R14 accepting the damage, and the walkdown performed in Li1R15 showed no growth in the damage.

- The acceptance criteria stated in the procedure specifies limits for "localized areas of corrosion." There is no evidence of corrosion in the affected area, only mechanical damage.
- The > 50 mils limit is specified for the drywell head. The general drywell head plate thickness is 1.5 inches, but the damage is located on the top edge of the 4-inch-thick mating flange. It stands to reason that the thicker flange could withstand greater material loss than the thinner plate.

Based on these reasons, engineering concluded that the damage identified above is acceptable for continued service.

The drywell head interior surface indications were also re-assessed and based on general visual examination, the areas surrounding the light surface corrosion on the interior surfaces of the drywell head are acceptable and have no additional deterioration or coating failure. These areas (<1 inch in diameter per area) showed light surface corrosion with negligible coating loss. No evidence of checking, cracking, blistering, flaking, scaling, peeling, discoloration, embrittlement or mechanical damage was observed on the interior surfaces of the drywell head. Based on engineering judgment and site procedural guidance, the drywell head internal surface as-found condition was acceptable for another cycle without coating repair. This was based on negligible coating loss in the affected areas and the fact that the drywell is inerted during operation (atmosphere not at risk of corrosion). It was also noted that the amount of coating loss is negligible and would not affect the suction strainers during a DBA. Re-coating of the internal surface indications was planned for the next outage, 1R16.

Unit 1 1R16 RFO – Spring 2016

The drywell head was previously inspected during the 1R14 RFO as part of the containment examination. Two areas of condition were documented. The indications were as follows:

- Bolt support between No. 51 and No. 52 shows apparent impact damage.
- Paint is chipped between all of the bolts and various areas around the head inner diameter and outer diameter surfaces.

The bolt support impact damage between No. 51 and No. 52 was justified to be acceptable as-is with no repairs necessary. 1R15 drywell coatings re-inspection walkdown (outer diameter and inner diameter) and evaluation justified the acceptability for an additional cycle (1R16).

The paint chipped at various locations on the outer diameter surfaces of the drywell head was scheduled to be repaired during 1R16 with the inner diameter to be recoated during 1R17. Based on the 1R16 re-inspection of the drywell head (outer diameter and inner diameter), no new coating chips were identified. However, additional impact damage areas (bolt support between No. 5 and No. 6; No. 45 and No. 46, No. 46 and No. 47, No. 42 and No. 43, and No. 34 and No. 35) relative to those previously identified in 1R14 were identified during the 1R16 walkdown.

The drywell head assembly consists of a 2 to 1 semi-ellipsoidal head and a cylindrical lower flange. The lower flange is supported on the top of the drywell wall. The head is made of a 1-

½ inch thick plate and is secured with eighty 2-¾ inch diameter bolts at the 4-inch-thick mating flange.

Engineering performed a walkdown on March 24, 2016, to re-inspect the coatings. The newly identified impact damages are similar to that identified in previous examinations. The impact has an average approximate length of 1.5 inches, a width of 0.2 inches and a depth of 1/16 inch. Per engineering judgment, the impact damages are too small and will not affect the flange design performance. Moreover, they are located between the bolts locations, far from the applied stresses. The drywell flange will meet its design function and proper torque can be applied. Therefore, no repair is required, and the drywell head can be used in the current condition for continued service.

The pictures of the coating, with previously identified degradation inside the drywell head, were reviewed by the site safety related coating program owner and compared to existing condition. The areas surrounding the chipped areas are identical to previously identified degradation and acceptable with no loose coating material. The chipped areas (< 1 inch in diameter per area) are showing very minor surface corrosion with negligible metal loss in the affected area and the fact that the drywell is inerted during operation (atmosphere not at risk for corrosion). A coating repair should be performed during 1R17 using an approved Service Level I coating and applicators/inspectors. It should also be noted that the amount of coating loss was negligible and would not affect the suction strainers during a DBA.

Based on the above justification, the drywell head flange is acceptable as-is with no repairs necessary. The coating degradation on the interior surface of the drywell head will not adversely impact the operability of primary containment (drywell) and was acceptable as-is for an additional cycle.

Unit 1 1R17 – Spring 2018

There was no drywell inspection performed in the 1R17 outage.

Unit 2 2R13 RFO – Spring 2015

During a walkdown of the Unit 2 drywell with an NRC ISI inspector, three areas of minor degradation were noted on the metal containment liner. Information for these areas of damage is noted below:

Location 1: Two locations were noted at elevation 309 feet, 125-degree azimuth (approximately ½-inch in length) where the paint is chipped with visible bare metal. This location was noted during the 2R11 scaffold removal walkdown but was not repaired since its initial identification and appears to be unchanged.

Location 2: Three indications were noted at elevation 283 feet, 270-degree azimuth (approximately ½ to 1-½ inches in length) where the paint is chipped with visible bare metal. This location was also noted during the 2R11 scaffold removal walkdown. Repair was performed in 2R12 but has since been re-damaged.

Location 3: Multiple locations were noted at elevation 253 feet, personnel hatch area where the paint is chipped with visible bare metal. There is one area along a weld at the grating level where the paint is removed and bare metal is visible for a length of approximately 18 inches.

It was conservatively assumed that each indication at locations 1 and 2 had an area of 20 square inches (average) of degraded coating. Also, it was conservatively assumed that location 3 had an area of 2 square feet of degraded coating. It was conservatively assumed that locations 1, 2 and 3 comprised a total of 2.2 square feet of degraded drywell liner coating.

The drywell steel liner plate is coated with Ameron Amercoat 90N per LGS specifications. The major concern with detached coatings is the potential to contribute to ECCS pump suction strainer debris loading should they fail during a LOCA. Therefore, the drywell steel liner coating is classified as a safety related service level I coating for LGS.

During power operation, the oxygen content of the primary containment atmosphere is maintained at a concentration no greater than 4 percent by volume. This limit is established to preclude the attainment of a combustible gas mixture inside the containment if combustible gases are released into the containment atmosphere following a postulated accident. This low oxygen atmosphere is achieved by displacing air in the primary containment with nitrogen gas. This nitrogen inerting of primary containment is achieved by the Containment Atmospheric Control (CAC) System.

The detached sections of coating (2.2 square feet) are assumed to travel to the suppression pool during a LOCA. This assumption is very conservative according to site procedural guidance. Per the guidance, a factor of 0.01-lb./square feet/mil is used for epoxy coatings. Amercoat 90 N is an epoxy coating and a typical application (two coats) shall have a dry film thickness of 8 mils. This would result in a total of 0.176 pounds of coating debris that would travel to the suppression pool and possibly impact the ECCS suction strainers. This additional ECCS pump suction strainer debris loading is considered negligible by inspection of the capacity of the strainers.

The LGS liner is a 1/4-inch mild carbon steel plate. The function of the liner is to provide a “gas tight” barrier for the primary containment. A review of site liner calculations indicated that significant margin exists in the liner plate design, as plate strain is less than 50% of allowable.

The accepted corrosion rate for uncoated mild carbon steel is 0.003 inches/year to 0.006 inches/year. Assuming a 0.010-inch/year corrosion rate for the two-year operating cycle, the maximum theoretical material loss for the affected (uncoated) areas would be 0.020 inches. This value is very conservative based on the assumed corrosion and the fact that the drywell is inerted during plant operation. The lack of oxygen in the drywell will further reduce the corrosion rate so that material loss of 0.020 inches will not be approached. Assuming the maximum material loss of 0.020 inches, the remaining liner plate thickness would only be reduced by 8 percent. This is much less than the available margin determined in the site calculations. Therefore, the liner will continue to perform its design function for the next operating cycle even if the as-found conditions would remain uncoated until Li2R14.

Unit 2 2R14 RFO – Spring 2017

The drywell head was inspected during 2R14 as part of the overall containment examination. The following conditions were noted:

- Mechanical damage with chipped coating on the containment seal plate (exterior surface), no metal loss.
- Mechanical damage on all bolting locations with minor surface corrosion and no evidence of metal loss on the drywell head lower flange (exterior surface).

The LGS coatings engineer and maintenance performed a walkdown to re-assess the condition of the drywell head coating, as previously identified during the 2R13 walkdown. The walkdown confirmed minor mechanical damage on the exterior surface of the drywell head/upper flange areas with missing coating, minor surface corrosion and no metal loss. The walkdown also confirmed missing coating at locations (between 210 and 260-degree azimuth) on the interior surface of the drywell head with no metal loss or surface corrosion.

The drywell head interior surface indications were re-assessed and, based on general visual examinations of the areas surrounding the interior surfaces of the drywell head, are acceptable and have no additional deterioration or coating failure. These areas (approximately 0.5 square inches per location) showed no surface corrosion with negligible coating loss. No evidence of checking, cracking, blistering, flaking, scaling, peeling, discoloration, embrittlement or mechanical damage was observed on the interior surface of the drywell head. Based on engineering judgment, the drywell head internal surface as-found is acceptable for another cycle without coating repair. This is based on negligible coating loss in the affected areas and based on the fact that the drywell is inerted during operation (atmosphere not at risk of corrosion). It also should be noted that the amount of coating loss is negligible and will not impact the ECCS strainers during a DBA. Re-coating of the internal surface indications is tracked for 2R15 (2019) using an approved service level I coating application and qualified service level I coating inspectors.

The coating degradations identified on the outside surface of the drywell head (upper flange areas, lower flange area and seal plate) are not part of the safety related coatings program. These areas appear degraded due to tool impacts from the removal and installation of the drywell head bolts (mechanical damage). Based on walkdown observations, the mechanical damage on the exterior surfaces did not exceed the occasional dings, scratches, scrapes, limits as described in site procedures.

Unit 1 Visual Examination of Containment Vessels and Internals

Unit 1 1R14 Outage – Spring 2012

During the Spring 2012, Li1R14 RFO, the following conditions, which were found during the Visual Examination of Containment Vessels and Internals, were evaluated:

Li1R14 - White Crystalline Deposits on the Unit 1 Bio-Shield

The CISI examination of the containment identified a white, crystalline deposit on the hinge for the Core Spray bio-shield door. The inspection also identified several bolts at the same elevation that had the same deposits around the outside of the bio-shield.

A chemical analysis was performed to determine the origination of the discovered material deposits. The substance was identified to be mainly comprised of potassium carbonates, hydroxides and sodium carbonate. The source for these deposits was determined to be from the grout that is inside the bio-shield. The chemical analysis also determined that the deposits were not corrosive to the carbon steel liner unless the deposits were exposed to standing water. The identified areas are located on the bio-shield in the upper elevations and are not subject to standing water.

Unit 1 1R16 RFO – Spring 2016

During the Spring 2016, Li1R16 RFO, the following conditions, which were found during the Visual Examination of Containment Vessels and Internals, were evaluated:

Li1R16 – Unit 1 Drywell As-Found Conditions

The LGS Coatings Engineer and contractor personnel performed a walkdown in 1R16 to re-assess the condition of the drywell liner coating on all elevations, as previously identified in 1R14, 1R15 and 1R16 walkdowns.

The walkdown re-confirmed that the drywell inner and outer liners have coating chips (from scaffold poles), missing coatings (surface prepped around existing and removed pipe hangers) and newly identified light surface on drywell subpile room floor (237'-11" elevation around 180 to 270 degrees azimuth). The following technical evaluation justifies the as-found conditions identified for continued service, until repairs are performed starting in the Unit 1 1R17 RFO.

Service Level I coatings are used in areas inside the reactor containment where the coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown. The coatings on the drywell liners/bioshield wall are considered service level I and are considered safety related. Hence, coating degradation on the liner surface of the drywell falls within the safety-related coatings program.

Primary containment is constructed of reinforced concrete and is lined with a carbon steel plate on the inside. The reactor shield wall is constructed of inner and outer carbon steel plates, with high-density grout between the two plates. The material deposits and chipped coating have been identified in the outer carbon steel plate (facing the drywell). The outer steel plate is 1-½ inches thick and is designed to withstand local loads transferred through pipe restraints and the drywell platform. The function of the reactor shield wall coating on the outer steel plate is to protect the steel surface from corrosion.

The drywell subpile room floor is made of ¼-inch thick liner plate on top of concrete diaphragm slab, except in certain places. Based on general visual examination (walkdown and review of pictures), the newly identified locations on the drywell subpile room floor are light surface corrosion/discoloration due to chipped paint with no metal loss observed.

Also, based on general visual examination and comparison to indications from previous outages, the drywell liner wall chipped coatings are identical. The areas surrounding the chipped coatings are identical to those previously identified and are acceptable with no metal loss or loose coating material.

Based on engineering judgment, discussion with the ISI Engineer, and guidance provided in site procedures, the drywell liner/bio-shield wall and subpile room floor “as-found” conditions are acceptable for another cycle without immediate coating repair. This is based on negligible coating loss in the affected areas, light surface corrosion/ discoloration on the subpile floor room, and the fact that the drywell is inerted during operation (atmosphere is not at risk of corrosion). The mechanical damage (scaffold picks) on the drywell liner coatings is minimal, per engineering judgment. Therefore, there is no impact to the Unqualified Coating calculation or the ECCS suction strainers design analysis. The drywell liner coatings removed by the structural steel supports were mechanically removed and not deemed coating loss or unqualified.

Recoating of the identified surface indications is planned for 1R17 using an approved Service Level I coating application and qualified Service Level I coating inspectors.

Li1R16 – Area of Flaking Concrete / Paint in Reactor Building Room 108

A visual inspection of the drywell external surfaces identified a localized area of flaking concrete and/or paint located in the reactor building room 108, 177’ Elevation. The wall in question is the containment (Suppression Pool) wall, which is one of the walls in the Reactor Core Isolation Cooling (RCIC) pump room. It was determined that the subject indication was a crack in the wall coating. No crack was visible around the indication on the bare concrete behind the coating. The surface was mildly tapped to observe the soundness of the affected surface. It sounded structurally tight and sound. There was no leakage or any sign of leaching. The wall was evaluated to be structurally sound and will continue to perform its intended function. The coating was evaluated for repair in a future outage.

Li1R16 – Coating Damage on Containment Exterior Wall Room 102

A general visual examination of the containment outside surfaces revealed coatings damage in 14 areas located in Room 102, 177’ Elevation of the reactor building. The coating was evaluated for repair in a future outage.

Li1R16 – Coating Damage on Containment Exterior Wall Room 103

A general visual examination of the containment outside surfaces revealed coatings damage in 4 areas. The coating was evaluated for repair in a future outage.

Li1R16 – Liner Indications on Containment Exterior Wall

A general visual examination of the outside containment surfaces on 177’ Elevation revealed several indications: Room 114 – several areas of vertical and horizontal hairline linear indications; Room 117 – several vertical and horizontal liner indications; Room 109 – an area of flaking paint; Room 288 – access through room 109 – vertical and horizontal linear indications and a pop out. The Structural Monitoring Engineer performed a walkdown to evaluate the observed conditions. The following assessments were made:

The horizontal and vertical liner indications noted in Rooms 114,117 and 288 are hairline surface cracks. The hairline surface (shrinkage) cracks/indications do not compromise the structural integrity of the wall.

The observed flaking paint in Room 109 is minimal. The concrete is sound at and around the observed flaking. The coating is a Class 2 coating and has no safety impact.

The observed pop out is small (less than 3/16-inch in depth and 4 inches in any surface dimension) and does not require further evaluation. Some smaller pop outs that were noted seem to be minor imperfections (less than 3/16-inch deep) in concrete and seem to have occurred during construction (placement of concrete/curing). These observed locations are not active and are judged to be insignificant. The wall integrity is not compromised and will continue to perform its function.

Li1R16 - Linear Concrete Indication – Reactor Building Room 289

During an examination of Room 289 of the Reactor Building, 201' Elevation, a linear indication was found in the concrete that extends vertically from the 201' Elevation to just below the 217' Elevation. The wall in question was the containment (Suppression Pool) wall. The observed crack is a tight surface crack on the concrete wall. No leakage or leaching was observed. The surface crack required no additional evaluations. The wall is structurally sound and continues to perform its safety function.

Li1R16 – Linear Concrete Indication – Reactor Building 201' Elevation

A general visual examination of the outside containment surfaces revealed a linear indication that runs 300 degrees azimuth throughout all rooms except Room 204 on the 201' Elevation. In Rooms 203 and 207, a vertical liner indication extends from the 300-degree linear. An area of flaking paint was observed 4.5 feet above the floor in Room 204. A pop out was noted in Room 2012 in an area that previously had a bolt or drilled hole. The horizontal crack is a hairline surface crack that goes almost all around (approximately 300 degrees azimuth). Similarly, there are vertical indications at some places. These vertical indications were also determined to be hairline surface cracks. The hairline surfaces (shrinkage) cracks/indications do not compromise the wall structure.

The observed flaking paint in Room 204 is minimal. The concrete is sound at and around the flaking. This coating is Class 2 and has no nuclear safety impact.

The observed pop out in Room 210 should be reclassified as scaling. Based on the observed condition, the scaling is shallow and less than 3/16-inch in depth and does not require further evaluation. The wall integrity was not compromised, and the wall will continue to perform its intended safety function.

Li1R16 – Linear Indications 253' Elevation

A general visual examination of 253' Elevation observed several indications. A liner indication was found in Room 402. Linear indications and an area of flaking paint along with concrete damage in an area of a bolt hole were observed in Room 407. The wall in question is the exterior (Drywell) containment wall, which is surrounded by all the rooms mentioned above. The horizontal and vertical linear indication noted in Room 402 and 407 are hairline surface cracks. These hairline surface (shrinkage) cracks/indications do not compromise the structural integrity of the wall. The area of concrete damage around the bolt hole was found to be insignificant and does not compromise the structural integrity of the wall. No further evaluation was required. The area was recommended to be recoated in a future outage.

Li1R16 – Linear Indications and Missing Caulking

A general visual examination of the containment penetrations revealed the following indications: Penetration X-8 – 253' Elevation, Room 407 – Caulking missing from around the base plate, signs of corrosion on the penetration with water staining below the penetration; Penetration X-14 – 283' Elevation, Room 510 – Linear indications extending out from the penetration into the concrete and caulking around the base plate of the penetration is missing; Penetration X-59A – 283' Elevation, Room 522 – Several linear indications extending out from the base plate into the concrete and missing caulking from around the penetration to the base plate. The cracks/linear indications on Penetration X-59A are hairline cracks. These indications do not compromise the structural integrity of the wall and do not require further evaluation. The missing caulking is actually grout, which is more of a cosmetic nature rather than structural. Missing grout between the penetration pipe and the embedded plate has no impact on the wall or the penetration. The indications found on Penetration X-14 were found to be insignificant and no further action was necessary. The observed corrosion on Penetration X-8 and containment was found to be surface corrosion leaving the penetration to be structurally sound and acceptable for continued service. The area was recommended to be recoated in a future outage.

Li1R16 – Linear Indication on Wall – Room 523

A general visual examination of the outside containment surfaces revealed a linear indication that ran vertically up the wall next to Penetration X-29B and X-117A in Room 523. The wall in question was the containment (Drywell) exterior wall. No significant cracks were identified. The observed cracks were tight and matched the appearance of shrinkage. The wall is structurally sound and continues to perform its intended function.

Li1R16 – Linear Indications on 283' Outer Containment Wall

A general visual examination of the outside containment surfaces revealed linear indications in Rooms 501 and 506. Room 510 had a linear indication next to Penetration X-14. The wall in question is the exterior (Drywell) containment wall, which is surrounded by Rooms 501, 506 and 510 mentioned above. The linear indications noted in Room 506 are hairline surface cracks. The linear horizontal and vertical indications noted in Room 501 are tight surface cracks. The noted indications do not compromise the structural integrity of the wall.

Li1R16 – Linear Indication – 313' Elevation

A general visual of the outside containment surfaces revealed a linear indication that ran 360 degrees throughout all rooms on the 313' Elevation in Rooms 602, 605, 605A and 605B.

Leaking was also observed on the floor in Room 605B, containment wall and on an overhead piping. The cracks identified were found to be tight, matched the appearance of shrinkage cracks, and did not require further evaluation. The observed leakage appeared to show signs of prior known leakage that occurred. No additional actions were required.

Unit 2 Visual Examination of Containment Vessels and Internals

Unit 2 Li2R12 RFO – Spring 2013

During the Spring 2013, Li2R12 RFO, the following conditions, which were found during the Visual Examination of Containment Vessels and Internals, were evaluated:

Li2R12 – Drywell Head Exterior Coating Condition

General visual examination identified coating damage above the drywell head bolt hole 30. The damage was a 40-square inch area on the exterior of the drywell head. No degradation to the drywell head was observed. The coating was repaired during Li2R13.

Li2R12 – Coating Pop out with No Apparent Degradation of Substrate

During the general visual examination of the concrete containment, it was identified that coating was missing (“popped-out”) with no apparent degradation to the substrate. This condition was identified in Room 184, approximately 4 feet above the floor. The missing coating was estimated to be 8 inches long by 3 inches wide. There was no degradation to the containment and the observed condition does not impact the ability for containment to perform its function.

Li2R12 – Indication in the Concrete in Room 174

An examination of the containment identified a surface crack that runs the length of Room 174. The indication appeared to be a surface indication and appeared to have been previously repaired. The indication was determined to be a crack in the wall coating. No leakage or any sign of leaching was observed. No additional actions were necessary.

Li2R12 – Pop out Observed in Room 479

An examination of the containment revealed concrete pop out in Room 479. The wall in question is the containment (Drywell) wall, which is one of the walls in the Transverse Incore Probe Room. The concrete was found to be sound. The pop out was not due to degradation or environmental effects. No additional actions were necessary.

Li2R12 – Evaluate Missing Coating above Penetration X-7C

An examination of the containment identified missing coating above Penetration X-7C with no apparent degradation of substrate. The missing coating was evaluated and recommended to be recoated in a future outage. No additional actions were necessary.

Unit 2 2R14 RFO – Spring 2017

During the Spring 2017, Li2R14 RFO, the following conditions, which were found during the Visual Examination of Containment Vessels and Internals, were evaluated.

Li2R14 – Drywell Head Penetration X-4 Access Manway Loose Bolting

A general visual examination of Penetration X-4 found 2 of the 16 bolts to be loose and could be turned by hand. The bolting was subsequently tightened during Li2R14.

Li2R14 – Drywell Equipment Access Hatch Bolt Damage

Visual examination of the drywell equipment access hatch (Penetration X-1) bolted connection identified mechanical damage to the threads on three of the bolts (Bolts 2, 11, and 24). Bolt 2 had one flattened thread, Bolt 11 had 2 flattened threads, and Bolt 24 had 4 flattened threads. The area of the mechanical damage was at the bottom of the threaded portion of the bolt and was outside the area of thread engagement for the nut. Since the damage was outside of the thread engagement, it was determined to not have a negative impact on the ability of the bolting to perform its function during service. No additional actions were required.

Li2R14 – Drywell Personnel Airlock Bolt Damage

Visual examination of the drywell personnel airlock (Penetration X-2) bolted connection identified mechanical damage to the threads on two of the swing bolts (Bolts 16 and 18). Bolt 16 had 5 flattened threads and Bolt 18 had 3 flattened threads. The area of mechanical damage was at the bottom of the threaded portion of the swing bolt and was outside of the area of thread engagement for the nut. Since the damage was outside of the thread engagement, it was determined to not have a negative impact on the ability of the bolting to perform its function during service. No additional actions were required.

Li2R14 – Mechanical Damage on Seal Plate to Drywell Head Flange

General visual examination of the accessible inside and outside surfaces of the containment liner extension from the seal plate to the drywell head flange revealed the following conditions: mechanical damage with chipped coating on the seal plate and mechanical damage on all bolting locations with minor surface rust with no evidence of material loss below the flange. An evaluation revealed that the coating was not required by Code and had no impact on station operation.

3.7 License Renewal Aging Management

By letter dated June 22, 2011 (Reference 27), Exelon submitted its application to the Nuclear Regulatory Commission (NRC) for renewal of the LGS operating license for an additional 20 years. NUREG-2171, “Safety Evaluation Report Related to the License Renewal of Limerick Generating Station, Units 1 and 2,” dated September 2014 (Reference 28) documents the technical review of the LGS, Units 1 and 2, license renewal application by the NRC staff.

3.7.1 Aging Management Programs (AMPs)

ASME Section XI, IWE Program

The LGS, Units 1 and 2 Primary Containments are GE BWR, Mark II type seismic Category I safety-related structures. The Primary Containment is a reinforced concrete structure consisting of a cylindrical suppression chamber beneath a truncated conical drywell. The conical portion of the Primary Containment (drywell) encloses the reactor vessel, reactor coolant recirculation loops, and associated components of the RCS. The drywell is separated from the wetwell, (i.e., the pressure-suppression chamber and pool), by the drywell floor, also named the diaphragm slab. The suppression chamber stores a large volume of water and also contains the ECCS suction strainers, and the downcomer pipes, which terminate below the water level. The cone and cylinder form a structurally integrated reinforced concrete vessel, lined with steel plate and closed at the top of the drywell with a steel domed head. The inside surface of the Primary Containment is lined with a welded carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions. The personnel airlock, equipment hatch and other hatches provide access to the drywell and suppression chamber.

a. The ASME Section XI, Subsection IWE aging management program is an enhanced program that was developed to satisfy the requirements of 10 CFR 50.55a, Codes and Standards. The scope of the program includes the carbon steel liner, integral attachments, containment penetrations, containment hatches and airlocks; diaphragm slab carbon steel liner, downcomers and pressure-retaining bolting. The LGS Primary Containment design does not include a moisture barrier as shown in Figure IWE 2500-1; both the diaphragm slab and base slab are covered with a steel liner, which is welded to the vertical wall liner. The Primary Containment reinforced concrete elements are not within the scope of LGS ASME Section XI, Subsection IWE aging management program. The reinforced concrete elements are included in the scope of ASME Section XI, Subsection IWL. The AMP is currently in its second 10-Year inspection interval. The ASME Section XI, Subsection IWE aging management program complies with ASME Subsection IWE for metallic shell and penetration liners of Class CC pressure retaining components of ASME Section XI, 2001 Edition with 2003 Addenda, as approved in 10 CFR 50.55a(a)(3)(i). Per 10 CFR 50.55a(g)(4)(ii), the program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified twelve months before the start of the inspection interval.

b. The ASME Section XI, Subsection IWE aging management examination methods are visual examination (general visual, VT-1, and VT-3) with limited volumetric examination (ultrasonic thickness measurement) as necessary when augmented examinations are required. Surface examinations (liquid penetrant) could be performed if necessary, but are not normally required. The ASME Section XI, Subsection IWE aging management program plan and procedures specify or reference acceptance criteria, corrective actions, and expansion of the inspection scope, when degradation exceeding the acceptance criteria is found in accordance with applicable IWE requirements.

c. Existing procedures address examination of coated areas requiring augmented examination for evidence of flaking, blistering, peeling, discoloration or other signs of distress consistent with Subsection IWE-2310. The Protective Coating Monitoring and Maintenance Program is also implemented within the Primary Containment to ensure ECCS operability.

d. Aging management activities, recommended in the Final Interim Staff Guidance LR-ISG-2006-01, "Plant-Specific Aging Management Program for Inaccessible Areas of Boiling Water Reactor (BWR) Mark I Steel Containments Drywell Shell," needed to address the potential loss of material due to corrosion in the inaccessible areas of the BWR Mark I steel containment are not applicable to the LGS Mark II Concrete Primary Containment structures.

e. Cracking of containment bellows and testing of two-ply bellows described in IN 92-20 and surface examination of dissimilar metal welds of vent line bellows, are not applicable to the LGS Primary Containments. This is because there are no pressure boundary bellows, no vent line bellows, and no dissimilar metal welds of vent line bellows associated with the LGS Primary Containments. The ASME Section XI, Subsection IWE aging management program addresses and requires visual examinations of pressure-retaining bolted connections. For bolted connections, the program also relies on the design change procedures that will be enhanced to address NUREG-1339 (Reference 42) and industry recommendations delineated in the Electric Power Research Institute (EPRI) NP-5769, NP-5067, and TR-104213 guidance to ensure proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. The LGS ASME Section XI, aging management program complies with Subsection IWE for metallic shell and penetration liners of Class CC pressure retaining components of ASME Section XI, 2001 Edition with 2003 Addenda, as approved in 10 CFR 50.55a(a)(3)(i). The 10 CFR 50, Appendix J pressure testing is conducted in accordance with the 10 CFR 50, Appendix J aging management program for IWE pressure boundary components.

Overall NUREG-1801 (Reference 43) Consistency

The ASME Section XI, Subsection IWE AMP is an enhanced program that is consistent with NUREG-1801, "Generic Aging Lessons Learned," AMP XI.S1, "ASME Section XI, Subsection IWE," with no exceptions and with enhancements defined below.

Summary of Enhancements to NUREG-1801

1. Manage the suppression pool liner and coating system to:

   a. Remove any accumulated sludge in the suppression pool every RFO.

   b. Perform an ASME IWE examination of the submerged portion of the suppression pool each ISI period.

   c. Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following prior to the period of extended operation (PEO):

- Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 50 mils plate thickness loss will be recoated in the outage they are identified. This plate thickness loss criterion for local areas will also be used to determine when the submerged portions of the liner require augmented inspection, in accordance with ASME Section XI, Subsection IWE, Category E-C.

- Areas of general corrosion greater than 25 mils average plate thickness loss will be recoated based on ranking of affected surface area, high to low. This plate thickness loss criterion for areas of general corrosion will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

- For plates with greater than 25 percent coating depletion, the affected area will be recoated based on ranking of affected surface area depleted and metal thickness loss.

d. Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following during the PEO:

- Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 50 mils plate thickness loss will be recoated in the outage they are identified. This plate thickness loss criterion for local areas will also be used to determine when the submerged portions of the liner require augmented inspection, in accordance with ASME Section XI, Subsection IWE, Category E-C.

- Areas of general corrosion greater than 25 mils average plate thickness loss will be recoated based on ranking of affected surface area, high to low. This plate thickness loss criterion for areas of general corrosion will also be used to determine when the submerged portions of the liner require augmented inspection, in accordance with ASME Section XI, Subsection IWE, Category E-C.

- For plates with greater than 25 percent coating depletion, the affected area will be recoated based on ranking of affected surface area depleted and metal thickness loss.

The coating maintenance plan was initiated in the 2012 RFO for Unit 1 and the 2013 RFO for Unit 2. The coating maintenance plan will continue through the period of extended operation to ensure the coating protects the liner to avoid significant material loss.

2. Use the results of the ASME IWE inspection of the submerged portions of the suppression pool downcomers to perform the following:

- Local areas (less than or equal to 5.5 inches in any direction) that have 40 mils or more metal thickness loss will be recoated. This downcomer metal thickness loss criteria for local areas will also be used to determine when the submerged portions of the downcomers require augmented inspection, in accordance with ASME Section XI, Subsection IWE, Category E-C.

- Areas of general corrosion (greater than 5.5 inches in any direction) that have 30 mils or more metal thickness loss will be recoated. This downcomer metal thickness loss criteria for areas of general corrosion will also be used to determine when the submerged portions of the downcomers require augmented inspection, in accordance with ASME Section XI, Subsection IWE, Category E-C.

  The downcomer recoat and augmented inspection criteria will be implemented prior to receipt of the renewed licenses.

3. When IWE examinations are conducted, perform ultrasonic thickness measurements on four areas of submerged suppression pool liner affected by general corrosion. The ultrasonic thickness measurement requirements will be implemented prior to receipt of the renewed licenses.

4. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting.

These enhancements will be implemented prior to the period of extended operation.

ASME Section XI, IWL Program

The LGS, Units 1 and 2 Primary Containments are GE BWR, Mark II type seismic Category I safety-related structures. The Primary Containment is a reinforced concrete structure consisting of a cylindrical suppression chamber beneath a truncated conical drywell. The conical portion of the Primary Containment (drywell) encloses the reactor vessel, reactor coolant recirculation loops, and associated components of the RCS. The drywell is separated from the wetwell, (i.e., the pressure-suppression chamber and pool), by the drywell floor, also named the diaphragm slab. These areas are interconnected by downcomer vent pipes through the drywell floor that act to direct steam to the suppression pool within the chamber during a postulated LOCA. The suppression chamber stores a large volume of water. The cone and cylinder form a structurally integrated reinforced concrete vessel, lined with steel plate and closed at the top of the drywell with a steel domed head. The Primary Containment concrete structure is reinforced with conventional mild steel reinforcing. No part of the Primary Containment structure is prestressed concrete. The inside surface of the Primary Containment structure is lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions. The LGS, Units 1 and 2 Primary Containments are completely enclosed by the Reactor Enclosures. The Reactor Enclosure provides the secondary containment pressure boundary, shielding, shelter and protection for Primary Containment and the components housed within, against external design basis events.

The ASME Section XI, Subsection IWL AMP implements examination requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWL for reinforced and prestressed concrete containments (Class CC), 2001 Edition, with the 2003 Addenda, as approved in accordance with 10 CFR 50.55a(a)(3). The scope of the program includes the conventional reinforced concrete of the Primary Containment structure. These components consist of cylindrical suppression chamber beneath a truncated conical drywell, and the concrete base slab. No part of the Primary Containment is prestressed concrete, and therefore no testing of tendon wires, analysis of tendon corrosion medium, or measurement of prestressing forces is applicable to LGS. The LGS Primary Containment structure is reinforced with mild reinforcing steel with no unbonded post tensioning system. The AMP is implemented through the ISI Program Plan and procedures. The Primary Containment steel liner and its integral attachment are not within the scope of the ASME Section XI, Subsection IWL. The steel liner and its integral attachments are included in the scope of LGS ASME Section XI, Subsection IWE. The IWL program has been augmented to add the underside of the drywell floor (diaphragm slab) and the reactor pedestal to the IWL inspection scope.

The inspection methods specified in ASME Section XI, Subsection IWL aging management program are General and Detailed Visual examinations, in accordance with ASME Section XI, 2001 Edition, with the 2003 Addenda, Subsection IWL-2300.

Acceptance criteria specified in the program is in accordance with ASME Section XI, Subsection IWL. Conditions that do not meet acceptance criteria are entered into the corrective action program and evaluated by the Responsible Engineer. ASME Section XI, Subsection IWL requires examination of all containment concrete surfaces except as exempted by IWL-1220(b).

The ASME Section XI, Subsection IWL AMP complies with ASME Section XI, Subsection IWL, 2001 Edition including 2003 Addenda as approved by 10 CFR 50.55a. In accordance with 10 CFR 50.55a(g)(4)(ii), the LGS ISI program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified twelve months before the start of the inspection interval.

Overall NUREG-1801 (Reference 43) Consistency

The enhanced ASME Section XI, Subsection IWL AMP is consistent with the NUREG-1801, AMP XI.S2, “ASME Section XI, Subsection IWL,” with no exceptions and enhancements as described below.

Summary of Enhancements to NUREG-1801

Include the second-tier acceptance criteria of the American Concrete Institute (ACI) standard ACI 349.3R, Evaluation of Existing Nuclear Safety-Related Concrete Structures.

10 CFR 50, Appendix J Aging Management Program

The 10 CFR 50, Appendix J program conducts tests to assure that (a) leakage through the reactor containment and systems and components penetrating primary containment shall not exceed allowable leakage rate values as specified in the technical specifications or associated bases and (b) periodic surveillance of reactor containment penetrations is performed so that proper maintenance and repairs are made during the service life of the component, and systems and components penetrating containment. The Primary Containment Leakage Rate Testing Program provides for aging effects such as loss of material, loss of leak tightness, or loss of preload in various systems penetrating containment. The program also detects degradation of gaskets and seals. Per NEI 94-01, Section 6.0, General Requirements, an LLRT is not required for the following cases: 1) Primary containment boundaries that do not constitute potential primary containment atmospheric pathways during and following a DBA; 2) Boundaries sealed with a qualified seal system; or 3) Test connection vents and drains between primary containment isolation valves which are one inch or less in size, administratively secured closed and consist of a double barrier. For LGS, these vents and drains are administratively secured under site procedure, Primary Containment Integrity.

The LGS Primary Containment Leak Rate Testing Program is performed in accordance with approved procedures, which establish the requirements for development, implementation, and administration of a leak rate test program. The plant program document and procedures provide instructions for actual performance of the containment leak rate tests.

The LGS Primary Containment Leak Rate Testing Program is performed in accordance with the regulations and guidance provided in 10 CFR 50, Appendix J Option B, RG 1.163, NEI 94-01, ANSI/ANS 56.8, and approved plant program documents and procedures. LLRTs are performed to assure that leakage through systems and components penetrating primary containment does not exceed allowable leakage limits specified in the technical specifications. LLRTs are performed on containment pressure boundary barriers at frequencies that comply with the requirements of 10 CFR 50, Appendix J, Option B.

The Leak Rate program is credited with managing the aging degradation of pressure retaining boundaries of piping and components of the various systems penetrating the containment. Type A, or ILRTs, measure overall containment leakage as a whole. Type B and Type C, or LLRTs, which are also performed under this program, measure local leakage rates across each pressure-containing or leakage-limiting boundary for the primary containment isolation system containment penetrations. The method, extent and schedule of these tests will detect minor leakage prior to loss of intended function.

Examinations performed in accordance with ASME Section XI, Subsections IWE and IWL, verify containment structural integrity. The purpose of the inspection is to uncover any evidence of structural deterioration that may affect the containment structural integrity or leak-tightness. If there is evidence of structural deterioration, the Type A test is not performed until corrective action is taken in accordance with the repair/replacement procedures.

Overall NUREG-1801 (Reference 43) Consistency

The 10 CFR Part 50, Appendix J AMP is an existing program that is consistent with NUREG-1801, AMP XI.S4, “10 CFR Part 50, Appendix J.”

Structures Monitoring Aging Management Program

The Structures Monitoring program was developed and implemented to meet the regulatory requirements of 10 CFR 50.65, Maintenance Rule, RG 1.160, and NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” The program includes masonry walls evaluated in accordance with NRC Information Bulletin (IEB) 80-11, “Masonry Wall Design,” and incorporates guidance in NRC IN 87-67, “Lessons Learned from Regional Inspection of Licensee Actions in Response to IE Bulletin 80-11." The structures monitoring AMP incorporates all elements for the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (Reference 44), LG-PBD-AMP-XI.S7. The existing program will be enhanced to include additional structures and structural components that have been determined not to be in the scope of the Maintenance Rule; but are in the scope of license renewal and require aging management. The added structures, components and other enhancements are listed below.

The Structures Monitoring program is implemented by procedures that require periodic visual inspections by personnel qualified to monitor structures and components for applicable aging effects, such as those described in the American Concrete Institute Standards 349.3R, ACI 201.1R, and Structural Engineering Institute/American Society of Civil Engineers Standard (SEI/ASCE) 11-99. Visual inspections of high strength bolts (greater than or equal to 150 kilo-pounds per square inch (ksi) actual yield strength and greater than 1 inch in diameter) will be supplemented with volumetric or surface examinations if highly stressed susceptible bolting materials are found to be in a corrosive environment. Aging effects identified during inspections are evaluated by qualified personnel using criteria derived from industry codes and standards contained in the plant licensing basis and will be enhanced to include additional criteria contained in ACI 349.3R, ACI 318, SEI/ASCE 11-99, and the American Institute of Steel Construction (AISC) specifications, as applicable.

The Structural Monitoring Program relies on plant procedures that are consistent with guidance in NUREG-1339, and in EPRI guidance (NP-5769, NP-5067 and TR-104213) to ensure structural bolting integrity. The program will also be enhanced to include periodic sampling and testing of ground water and the need to assess the impact of any changes in its chemistry on below grade concrete structures.

Protective coatings are not relied upon to manage the effects of aging for structures included in the scope of this AMP.

Overall NUREG-1801 (Reference 43) Consistency

The enhanced Structures Monitoring AMP is an existing program that is consistent with NUREG-1801, AMP XI.S6, "Structures Monitoring," with no exceptions and the enhancements described below.

Summary of Enhancements to NUREG-1801

The Structures Monitoring program will be enhanced to:

1. Add the following structure:
    a. Admin Building Warehouse
    b. Fuel Oil Pumphouse
    c. Service Water Pipe Tunnel
    d. Yard Structures
        - Aux Fire Water Storage Tank Foundation
        - Backup Fire Pump House and Foundation
        - Well Pump #3 Enclosure and Foundation
        - Railroad Bridge

- Manholes 001 and 002
- Fuel Oil Storage Tank Dike
- Transformer foundations and dikes

2. Add the following components and commodities:
    a. Pipe, electrical, and equipment component support members
    b. Pipe whip restraints and jet impingement shields
    c. Panels, Racks, and other enclosures
    d. Sliding surfaces
    e. Sump and Pool liners
    f. Electrical cable trays and conduits
    g. Electrical duct banks
    h. Tube tracks
    i. Doors
    j. Penetration seals
    k. Blowout panels
    l. Permanent drywell Shielding
    m. Roof scuppers

3. Monitor groundwater chemistry on a frequency not to exceed 5 years for pH, chlorides, and sulfates and verify that it remains non-aggressive, or evaluate results exceeding criteria to assess impact, if any, on below-grade concrete.

4. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. Revise storage requirements for high strength bolts to include recommendations of Research Council on Structural Connections (RSCS) Specification for Structural Joints Using High Strength Bolts, Section 2.0.

5. Monitor concrete for areas of abrasion, erosion, and cavitation degradation, dummy areas that can exceed the cover concrete thickness in depth, pop outs and voids, scaling and passive settlements or deflections.

6. Perform inspections on a frequency not to exceed 5 years.

7. Perform inspections of sub-drainage sump pit internal concrete on a 5-year frequency as a leading indicator the condition of below grade concrete exposed to ground water.

8. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R.

9. Perform inspection of elastomeric vibration isolation elements and structural seals for cracking, loss of material and hardening. Visual inspections of elastomeric vibration isolation elements are to be supplemented by manipulation to detect hardening when vibration isolation function is suspect.

10. Monitor accessible sliding surfaces to detect significant loss of material due to wear, corrosion, debris, or dirt that could result in lock-up or reduced movement.

11. Perform opportunistic inspection of below grade portions of in-scope structures in the event of excavation when exposes normally inaccessible below grade concrete.

12. Include applicable acceptance criteria from ACI 349.3R.

13. Clarify that loose bolts and nuts and cracked high strength bolts are not acceptable unless accepted by engineering evaluations.

Protective Coating Monitoring and Maintenance Program

The Protective Coating Monitoring and Maintenance Program provides for aging management of Service Level I coatings inside the LGS primary containment. The failure of the Service Level I coatings could adversely affect the operation of the ECCS by clogging the ECCS suction strainers. Proper maintenance of the Service Level I coating ensures that coating degradation will not impact the operability of the ECCS systems. The Protective Coating Monitoring and Maintenance Program provides for coating system inspection, assessment, and repair for any condition that adversely affects the ability of Service Level I coatings to function as intended.

Service Level I coatings will prevent or minimize the loss of material due to corrosion but these coatings are not credited for managing the effects of corrosion for the carbon steel containment liners and components at LGS. This program ensures only that the Service Level I coatings maintain adhesion so as to not affect the intended function of the ECCS suction strainers. The Protective Coating Monitoring and Maintenance Program currently implemented will be enhanced as described below to be a comparable program to that described in Regulatory Position C4 of NRC RG 1.54, Revision 2. The current program is described in the LGS response to Generic Letter 98-04, “Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment.”

As discussed throughout the 10 Elements, the Protective Coating Monitoring and Maintenance Program is comparable to a condition assessment program for Service Level I protective coatings, as described in RG 1.54, Revision 2 (Reference 45), Regulatory Position C4.

Service Level I coatings are not credited for managing the effects of corrosion for the carbon steel containment liners and components at LGS. This program only ensures that the Service Level I coatings maintain adhesion so as to not affect the intended function of the ECCS suction strainers.

Overall NUREG-1801 (Reference 43) Consistency

The Protective Coating Monitoring and Maintenance Program is an existing program that is consistent with NUREG-1801 AMP XI.S8, Protective Coating Monitoring and Maintenance Program with enhancements described below.

Summary of Enhancements to NUREG-1801

This program will be enhanced to create the position of Nuclear Coatings Specialist qualified to ASTM D7108 standards at Limerick.

3.8 NRC SER Limitations and Conditions

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

The NRC staff found that the use of NEI TR 94-01, Revision 2, was acceptable for referencing by licensees proposing to amend their TS to permanently extend the ILRT surveillance interval to 15 years, provided the following conditions, as listed in Table 3.8.1-1, are satisfied:

Table 3.8.1-1, NEI 94-01 Revision 2-A Limitations and Conditions

Limitation/Condition **(From Section 4.0 of SE)**	**LGS Response**
For calculating the Type A leakage rate, the licensee should use the definition in the NEI TR 94-01, Revision 2, in lieu of that in ANSI/ANS-56.8-2002. (Refer to SE Section 3.1.1.1.)	LGS will utilize the definition in NEI 94-01, Revision 3-A, Section 5.0. This definition has remained unchanged from Revision 2-A to Revision 3-A of NEI 94-01.
The licensee submits a schedule of containment inspections to be performed prior to and between Type A tests. (Refer to SE Section 3.1.1.3.)	Reference Sections 3.5.3 and 3.5.4 of this submittal.
The licensee addresses the areas of the containment structure potentially subjected to degradation. (Refer to SE Section 3.1.3.)	Reference Section 3.5.3 and Section 3.6.7 of this submittal.
The licensee addresses any tests and inspections performed following major modifications to the containment structure, as applicable. (Refer to SE Section 3.1.4.)	There are no major modifications planned that would require the performance of a Type A ILRT or a Structural Integrity Test (SIT).

Table 3.8.1-1, NEI 94-01 Revision 2-A Limitations and Conditions	
Limitation/Condition **(From Section 4.0 of SE)**	**LGS Response**
The normal Type A test interval should be less than 15 years. If a licensee has to utilize the provision of Section 9.1 of NEI TR 94-01, Revision 2, related to extending the ILRT interval beyond 15 years, the licensee must demonstrate to the NRC staff that it is an unforeseen emergent condition. (Refer to SE Section 3.1.1.2.)	LGS will follow the requirements of NEI 94-01, Revision 3-A, Section 9.1. This requirement has remained unchanged from Revision 2-A to Revision 3-A of NEI 94-01. In accordance with the requirements of NEI 94-01, Revision 2-A, SER Section 3.1.1.2, LGS will also demonstrate to the NRC staff that an unforeseen emergent condition exists in the event an extension beyond the 15-year interval is required.
For plants licensed under 10 CFR Part 52, applications requesting a permanent extension of the ILRT surveillance interval to 15 years should be deferred until after the construction and testing of containments for that design have been completed and applicants have confirmed the applicability of NEI 94-01, Revision 2, and EPRI Report No. 1009325, Revision 2, including the use of past containment ILRT data.	Not applicable. LGS was not licensed under 10 CFR Part 52.

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

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

Topical Report Condition 1

NEI TR 94-01, Revision 3, is requesting that the allowable extended interval for Type C LLRTs be increased to 75 months, with a permissible extension (for non-routine emergent conditions) of nine months (84 months total). The staff is allowing the extended interval for Type C LLRTs be increased to 75 months with the requirement that a licensee's post-outage report include the margin between the Type B and Type C leakage rate summation and its regulatory limit. In addition, a corrective action plan shall be developed to restore the margin to an acceptable level. The staff is also allowing the non-routine emergent extension out to 84-months as applied to Type C valves at a site, with some exceptions that must be detailed in NEI TR 94-01, Revision 3. At no time shall an extension be allowed for Type C valves that are restricted categorically (e.g., BWR MSIVs), and those valves with a history of leakage, or any valves held to either a less than maximum interval or to the base refueling cycle interval. Only non-routine emergent conditions allow an extension to 84 months.

Response to Condition 1

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

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

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

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

Response to Condition 1, Issue 1

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

Response to Condition 1, Issue 2

When the potential leakage understatement adjusted Types B and C MNPLR total is greater than the LGS administrative leakage summation limit of 0.50 L_a, but less than the regulatory limit of 0.6 L_a, then an analysis and determination of a corrective action plan shall be prepared to restore the leakage summation margin to less than the LGS 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 so as to maintain an acceptable level of margin.

Response to Condition 1, Issue 3

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

Topical Report Condition 2

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

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

Response to Condition 2

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

- ISSUE 1 - Extending the LLRT intervals beyond 60-months and up to 75-month interval should be similarly conservative provided an estimate is made of the potential understatement and its acceptability determined as part of the trending specified in NEI TR 94-01, Revision 3, Section 12.1.

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

Response to Condition 2, Issue 1

The change in going from a 60-month extended test interval for Type C tested components to a 75-month interval, as authorized under NEI 94-01, Revision 3-A, represents an increase of

25% in the LLRT periodicity. As such, LGS, Units 1 and 2 will conservatively apply a potential leakage understatement adjustment factor of 1.25 to the actual As-Left leak rate, which will increase the As-Left leakage total for each Type C component currently on greater than a 60-month test interval up to the 75-month extended test interval. This will result in a combined conservative Type C total for all 75-month LLRTs being "carried forward" and will be included whenever the total leakage summation is required to be updated (either while on line or following an outage).

When the potential leakage understatement adjusted leak rate total for those Type C components being tested on greater than a 60-month test interval up to the 75-month extended test interval, is summed with the non-adjusted total of those Type C components being tested at less than or equal to a 60-month test interval, and the total of the Type B tested components, results in the MNPLR being greater than the LGS leakage summation limit of $0.50L_a$, but less than the regulatory limit of 0.6 L_a, then an analysis and corrective action plan shall be prepared to restore the leakage summation value to less than the LGS leakage limit. The corrective action plan shall focus on those components which have contributed the most to the increase in the leakage summation value and what manner of timely corrective action, as deemed appropriate, best focuses on the prevention of future component leakage performance issues.

Response to Condition 2, Issue 2

If the potential leakage understatement adjusted leak rate MNPLR is less than the LGS leakage summation limit of 0.50 L_a, then the acceptability of the greater than a 60-month test interval up to the 75-month LLRT extension for all affected Type C components has been adequately demonstrated and the calculated local leak rate total represents the actual leakage potential of the penetrations.

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

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

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

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

3.9 Conclusion

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

Based on the previous ILRTs conducted at LGS, Units 1 and 2, it may be concluded that the permanent extension of the containment ILRT interval from 10 to 15 years represents minimal risk to increased leakage. The risk is minimized by: continued Type B and Type C testing performed in accordance with Option B of 10 CFR 50, Appendix J, and the overlapping inspection activities performed as part of the following LGS inspection programs:

- Containment Inservice Inspection Programs (IWE / IWL)
- Inspections of Service Level 1 Protective Coatings
- Maintenance Rule Structural Monitoring Program

This experience is supplemented by risk analysis studies, including the LGS risk analysis provided in Attachment 3. The findings of the risk assessment confirm the general findings of previous studies, on a plant-specific basis, that extending the ILRT interval from 10 to 15 years results in a very small change to the LGS, Units 1 and 2 risk profiles.

4.0 REGULATORY EVALUATION

4.1 Applicable Regulatory Requirements/Criteria

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

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

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

EPRI TR-1009325, Revision 2, provides a risk impact assessment for optimized ILRT intervals up to 15 years, utilizing current industry performance data and risk informed guidance.
NEI 94-01, Revision 3-A, Section 9.2.3.1 states that Type A ILRT intervals of up to 15 years are allowed by this guideline. The Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals, EPRI Report 1018243 (Formerly TR-1009325, Revision 2) indicates that, in general, the risk impact associated with ILRT interval extensions for intervals up to 15 years is small (Reference 19); however, plant-specific confirmatory analyses are required.

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

For EPRI Report No. 1009325, Revision 2, a risk-informed methodology using plant-specific risk insights and industry ILRT performance data to revise ILRT surveillance frequencies, the NRC staff finds that the proposed methodology satisfies the key principles of risk-informed decision-making applied to changes to TS as delineated in RG 1.177, An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications, and RG 1.174 ((References 39 and 10, respectively). The NRC staff, therefore, found that this guidance was acceptable for referencing by licensees proposing to amend their TS in regards to containment leakage rate testing, subject to the limitations and conditions noted in Section 4.0 of the SER.

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

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

4.2 Precedence

This LAR is similar in nature to the following license amendments for extending the Type A test frequency to 15 years and the Type C test frequency to 75 months, as previously authorized by the NRC:

- Surry Power Station, Units 1 and 2 (Reference 29)
- Donald C. Cook Nuclear Plant, Units 1 and 2 (Reference 30)
- Beaver Valley Power Station, Unit Nos. 1 and 2 (Reference 31)
- Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 (Reference 32)
- Peach Bottom Atomic Power Station, Units 2 and 3 (Reference 33)
- Comanche Peak Nuclear Power Plant, Units 1 and 2 (Reference 34)
- Catawba Nuclear Station, Units 1 and 2 (Reference 35)
- H. B. Robinson Steam Electric Plant, Unit No. 2 (Reference 36)
- Quad Cities Nuclear Power Station, Units 1 and 2 (Reference 37)
- Dresden Nuclear Power Station, Units 2 and 3 (Reference 38)

4.3 No Significant Hazards Consideration

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit or early site permit," Exelon Generation Company, LLC (Exelon) requests an amendment for Renewed Facility Operating License Nos. NPF-39 and NPF-85 for Limerick Generating Station (LGS), Units 1 and 2, respectively. The proposed change revises Units 1 and 2 Technical Specifications (TS) 6.8.4.g, "Primary Containment Leakage Rate Testing Program," to allow for the permanent extension of the Type A Integrated Leak Rate Testing (ILRT) and Type C Leak Rate Testing frequencies.

Specifically, the proposed change will revise LGS, Units 1 and TS 6.8.4.g, by replacing the references to Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program," with a reference to Nuclear Energy Institute (NEI) 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 3-A, and the limitations and conditions specified in NEI 94-01, Revision 2-A, as the documents used by LGS to implement the performance-based leakage testing program in accordance with Option B of 10 CFR 50, Appendix J.

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

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

Response: No.

The proposed activity involves the revision of the Limerick Generating Station (LGS), Units 1 and 2 Technical Specification (TS) 6.8.4.g, “Primary Containment Leakage Rate Testing Program,” to allow the extension of the Type A integrated leakage rate test (ILRT) containment test interval to 15 years and the extension of the Type C local leakage rate test (LLRT) interval to 75 months. The proposed activity also involves the extension of the drywell-to-suppression chamber bypass leak test (DWBT) from 120 months to 180 months to align the test with the proposed Type A test frequency. Per the guidance provided in Nuclear Energy Institute (NEI) 94-01, “Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J,” Revision 3-A, the current Type A test interval of 120 months (10 years) would be extended on a permanent basis to no longer than 15 years from the last Type A test. The current Type C test interval of 60 months for selected components would be extended on a performance basis to no longer than 75 months. Extensions of up to nine months (total maximum interval of 84 months for Type C tests) are permissible only for non-routine emergent conditions.

The proposed extensions do not involve either a physical change to the plant or a change in the manner in which the plant is operated or controlled. The containment is designed to provide an essentially leak tight barrier against the uncontrolled release of radioactivity to the environment for postulated accidents. As such, the containment and the testing requirements invoked to periodically demonstrate the integrity of the containment exist to ensure the plant's ability to mitigate the consequences of an accident, and do not involve the prevention or identification of any precursors of an accident.

The change in dose risk for changing the Type A test frequency from three-per-ten years to once-per-fifteen years, measured as an increase to the total integrated dose risk for all internal events accident sequences for LGS, is 6.60E-02 person-roentgen equivalent man(rem)/yr (0.36 percent) using the Electric Power Research Institute (EPRI) guidance with the base case corrosion included. The change in dose risk drops to 1.16E-02 person-rem/yr (0.06 percent) when using the EPRI Expert Elicitation methodology. The values calculated per the EPRI guidance are all lower than the acceptance criteria of ≤1.0 person-rem/yr or <1.0% person-rem/yr. The change in dose risk for changing the DWBT frequency from once-per-ten years to once-per-fifteen years, measured as an increase to the total integrated dose risk for all internal events accident sequences for LGS, is 1.5E-02 person-rem/yr. The results of the risk assessment for this amendment meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible. Therefore, this proposed extension does not involve a significant increase in the probability of an accident previously evaluated.

In addition, as documented in NUREG-1493, “Performance-Based Containment Leak-Test Program,” dated September 1995, Types B and C tests have identified a very large percentage of containment leakage paths, and the percentage of containment leakage paths that are detected only by Type A testing is very small. The LGS Type A test history supports this conclusion.

The integrity of the containment is subject to two types of failure mechanisms that can be categorized as: (1) activity based, and (2) time based. Activity based failure mechanisms are defined as degradation due to system and/or component modifications or maintenance. Local leak rate test requirements and administrative controls such as configuration management and procedural requirements for system restoration ensure that containment integrity is not degraded by plant modifications or maintenance activities. The design and construction requirements of the containment combined with the containment inspections performed in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components, Containment Maintenance Rule Structures Monitoring Program, Containment Coatings Program and TS requirements serve to provide a high degree of assurance that the containment would not degrade in a manner that is detectable only by a Type A test (ILRT). Based on the above, the proposed extensions do not significantly increase the consequences of an accident previously evaluated.

The proposed amendment also deletes Units 1 and 2 TS 6.8.4.g exceptions previously granted via TS Amendments No. 190 (Unit 1) and No. 151 (Unit 2) to allow one-time extensions of the ILRT test frequency for LGS. These exceptions were for activities that would have already taken place by the time this amendment is approved; therefore, their deletion is solely an administrative action that has no effect on any component and no impact on how the unit is operated.

Therefore, the proposed change does not 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 amendment to the LGS, Units 1 and 2 TS 6.8.4.g involves the extension of the LGS, Units 1 and 2 Type A (ILRT) containment test interval to 15 years and the extension of the Type C (LLRT) test interval to 75 months. The proposed activity also involves the extension of the DWBT from 120 months to 180 months to align the test with the proposed Type A test frequency. The containment and the testing requirements to periodically demonstrate the integrity of the containment exist to ensure the plant's ability to mitigate the consequences of an accident and do not involve any accident precursors or initiators.

The proposed change does not involve a physical change to the plant (i.e., no new or different type of equipment will be installed) nor does it alter the design, configuration, or change the manner in which the plant is operated or controlled beyond the standard functional capabilities of the equipment.

The proposed amendment also deletes Units 1 and 2 TS 6.8.4.g(a) exceptions previously granted to allow one-time extensions of the ILRT test frequency for LGS. These exceptions were for activities that would have already taken place by the time this amendment is approved; therefore, their deletion is solely an administrative action that has no effect on any component and no impact on how the unit is operated.

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

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

Response: No.

The proposed amendment to Units 1 and 2 TS 6.8.4.g involves the extension of the LGS Type A containment test interval to 15 years and the extension of the Type C test interval to 75 months for selected components. The proposed activity also involves the extension of the DWBT from 120 months to 180 months to align the test with the proposed Type A test frequency. This amendment does not alter the manner in which safety limits, limiting safety system set points, or limiting conditions for operation are determined. The specific requirements and conditions of the TS Containment Leak Rate Testing Program exist to ensure that the degree of containment structural integrity and leak-tightness that is considered in the plant safety analysis is maintained. The overall containment leak rate limit specified by TS is maintained.

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

The current frequency associated with a DWBT leakage test is 120 months. If any DWBT test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the NRC. If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 24 months until two consecutive tests meet the specified limit, at which time the test schedule may be resumed. The proposed change will modify this leakage test frequency from 120 months to 180 months. The proposed change is acceptable as the results from previous tests show that the measured drywell-to-suppression chamber bypass leakage at the current TS frequency has been a small percentage of the allowable leakage. Acceptability is further demonstrated by the design requirements applied to the primary containment components and other periodically performed primary containment inspections.

LGS, Units 1 and 2 TS SR 4.6.2.1.e DWBT monitors the combined leakage of three types of pathways: (1) the drywell floor and downcomers, (2) piping externally connected to both the drywell and suppression chamber air space and (3) the suppression chamber to drywell vacuum breakers. This amendment would extend the surveillance interval on the passive components of the test (the first two types of pathways), while retaining the current surveillance interval on the active components (suppression chamber to drywell vacuum breakers).

The proposed amendment also deletes Units 1 and 2 TS 6.8.4.g(a) exceptions previously granted to allow one-time extensions of the ILRT test frequency for LGS. These exceptions were for activities that would have already taken place by the time this amendment is approved; therefore, the deletion is solely an administrative action that has no effect on any component and no impact on how the unit is operated.

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

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

4.4 Conclusion

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

5.0 ENVIRONMENTAL CONSIDERATION

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

6.0 REFERENCES

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

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

3. ANSI/ANS 56.8-2002, “Containment System Leakage Testing Requirements,” dated November 27, 2002

4. RG 1.163, "Performance-Based Containment Leak-Test Program," September 1995

5. Letter from G.A. Hunger, Jr. (TMI) to NRC Document Control Desk, “Limerick Generating Station, Units 1 and 2 Technical Specification Change Request No. 95-14-0 Adoption of Performance-Based, 10 CFR 50, Appendix J Option B Testing,” dated June 28, 1996

6. Letter from G.A. Hunger, Jr. (TMI) to NRC Document Control Desk, “Limerick Generating Station, Units 1 and 2 Technical Specifications Change Request No. 95-14-0 Response to Request for Additional Information,” dated November 4, 1996

7. Letter from G.A. Hunger, Jr. (TMI) to NRC Document Control Desk, “Limerick Generating Station, Units 1 and 2 Technical Specifications Change Request No. 95-14-0 Adoption of Performance Based 10 CFR 50, Appendix J Option B Testing, Supplement,” dated November 5, 1996

8. Letter from G.A. Hunger, Jr. (TMI) to NRC Document Control Desk, “Limerick Generating Station, Units 1 and 2 Technical Specifications Change Request No. 95-14-0 Response to Request for Additional Information,” dated December 9, 1996

9. Letter from NRC (F. Rinaldi) to PECO Energy Company (G. A. Hunger, Jr.), Limerick Generating Station, Units 1 and 2 (TAC Nos. M96117 and M96118), dated January 24, 1997 (ML011560583)

10. RG 1.174, Revision 2, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” May 2011

11. RG 1.200, Revision 2, “An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities,” March 2009

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

13. NUREG-1493, “Performance-Based Containment Leak-Test Program,” January 1995

14. EPRI TR-104285, “Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals,” August 1994

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

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

17. ANSI/ANS 56.8-1994, “Containment System Leakage Testing Requirements,” dated August 4, 1994

18. Letter from NRC (P. Bamford) to C. G. Pierce, Limerick Generating Station, Units 1 and 2 – Issuance of Amendment Re: One-Time Type A Test Extension (TAC Nos. MD5198 and MD5199), dated February 20, 2008

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

20. 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, dated March 27, 2002

21. Letter from P. B. Cowan, Exelon Generation Company, LLC to NRC, Limerick Generating Station, Response to Request for Additional Information Technical Specifications Change Request – Type A Extension, dated September 2007 (ML072600355)

22. Columbia Generating Station Risk Assessment to Support ILRT (Type A) Interval Extension Request, ERIN No. C106-04-0001-5801, June 2004 (ML042230388)

23. ASME/ANS RA-Sa-2009, Addenda to ASME/ANS RA-S-2008, “Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications”

24. Regulatory Guide 1.200, An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment for Risk Informed Activities, Revision 1, January 2007

25. NEI Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines, NEI 07-12, Revision 1, June 2010

26. NRC Order EA-13-109, Issuance of Order to Modify Licenses with Regard to Reliable Hardened Containment Vents Capable of Operation Under Severe Accident Conditions, dated June 6, 2013

27. License Renewal Application for Limerick Generating Station Units 1 and 2, Facility Operating License Nos. NPF-39 and NPF-85, dated June 22, 2011

28. NUREG-2171, Safety Evaluation Report Related to the License Renewal of Limerick Generating Station, Units 1 and 2, dated September 2014

29. Letter from NRC (S. Williams) to Virginia Electric Power Company (D. A. Heacock), Surry Power Station, Units 1 and 2 – Issuance of Amendment Regarding the Containment Type A and Type C Leak Rate Tests, dated July 3, 2014 (ML14148A235)

30. Letter from NRC (A. W. Dietrich) to Indiana Michigan Power Company (L. J. Weber), Donald C. Cook Nuclear Plant, Units 1 and 2 – Issuance of Amendments Re: Containment Leakage Rate Testing Program, dated March 30, 2015 (ML15072A264)

31. Letter from NRC (T. A. Lamb) to First Energy Nuclear Operating Company (E. A. Larson), Beaver Valley Power Station, Unit Nos. 1 and 2 – Issuance of Amendment Re: License Amendment Request to Extend Containment Leakage Rate Test Frequency, dated April 8, 2015 (ML15078A058)

32. Letter from NRC (A. N. Chereskin) to Exelon Generation Company (G. H. Gellrich), Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 – Issuance of Amendments Re: Extension of Containment Leakage Rate Testing Frequency, dated July 16, 2015 (ML15154A661)

33. Letter from NRC (R. Ennis) to Exelon Nuclear (B. C. Hanson), Peach Bottom Atomic Power Station, Units 2 and 3 – Issuance of Amendments Re: Extension of Type A and Type C Leak Rate Test Frequencies (TAC Nos. MF5172 and MF5173), dated September 8, 2015 (ML15196A559)

34. Letter from NRC (B. Singal) to Luminant (R. Flores), Comanche Peak Nuclear Power Plant, Units 1 and 2 – Issuance of Amendments Re: Technical Specification Change for Extension of the Integrated Leak Rate Test Frequency From 10 to 15 Years (CAC Nos. MF5621 and MF5622), dated December 30, 2015

35. Letter from NRC (M. D. Orenak) to (K. Henderson), “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 (ML16299A113)

36. Letter from NRC (D. J. Galvin) to Duke Energy (R. M. Glover), “H. B. Robinson Steam Electric Plant, Unit No. 2 – Issuance of Amendment to Extend Containment Leakage Rate Test Frequencies (CAC No. MF7102),” dated October 11, 2016

Attachment 2

Mark-up of Technical Specifications Pages

Page 3/4 6-14 (Units 1 and 2) (for information – no changes are being made)
Page 6-14c (Units 1 and 2)

SURVEILLANCE REQUIREMENTS (Continued)

c. By verifying at least 8 suppression pool water temperature indicators in at least 8 locations, OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program with the temperature alarm setpoint for:

   1. High water temperature:

      a) First setpoint ≤ 95°F

      b) Second setpoint ≤ 105°F

      c) Third setpoint ≤ 110°F

      d) Fourth setpoint ≤ 120°F

d. By verifying at least two suppression chamber water level indicators OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program with the water level alarm setpoint for high water level ≤ 24'1-1/2".

e. Drywell-to-suppression chamber bypass leak tests shall be conducted to coincide with the Type A test at an initial differential pressure of 4 psi and verifying that the $A/\sqrt{k}$ calculated from the measured leakage is within the specified limit. If any drywell-to-suppression chamber bypass leak test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission. If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 24 months until two consecutive tests meet the specified limit, at which time the test schedule may be resumed.

f. By conducting a leakage test on the drywell-to-suppression chamber vacuum breakers at a differential pressure of at least 4.0 psi and verifying that the total leakage area $A/\sqrt{k}$ contributed by all vacuum breakers is less than or equal to 24% of the specified limit and the leakage area for an individual set of vacuum breakers is less than or equal to 12% of the specified limit. The vacuum breaker leakage test shall be conducted during each refueling outage for which the drywell-to-suppression chamber bypass leak test in Specification 4.6.2.1.e is not conducted.

c. By verifying at least 8 suppression pool water temperature indicators in at least 8 locations, OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program with the temperature alarm setpoint for:

   1. High water temperature:

      a) First setpoint ≤ 95°F

      b) Second setpoint ≤ 105°F

      c) Third setpoint ≤ 110°F

      d) Fourth setpoint ≤ 120°F

d. By verifying at least two suppression chamber water level indicators OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program with the water level alarm setpoint for high water level ≤ 24'1-1/2".

e. Drywell-to-suppression chamber bypass leak tests shall be conducted to coincide with the Type A test at an initial differential pressure of 4 psi and verifying that the $A/\sqrt{k}$ calculated from the measured leakage is within the specified limit. If any drywell-to-suppression chamber bypass leak test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission. If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 24 months until two consecutive tests meet the specified limit, at which time the test schedule may be resumed.

f. By conducting a leakage test on the drywell-to-suppression chamber vacuum breakers at a differential pressure of at least 4.0 psi and verifying that the total leakage area $A/\sqrt{k}$ contributed by all vacuum breakers is less than or equal to 24% of the specified limit and the leakage area for an individual set of vacuum breakers is less than or equal to 12% of the specified limit. The vacuum breaker leakage test shall be conducted during each refueling outage for which the drywell-to-suppression chamber bypass leak test in Specification 4.6.2.1.e is not conducted.

g. Primary Containment Leakage Rate Testing Program

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 Leakage Test program," dated September 1995, as modified by the following exception to~~ NEI 94-01, ~~Rev. 0,~~ "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J~~":~~

~~a. Section 9.2.3: The first Type A test performed after May 15, 1998 shall be performed no later than May 15, 2013.~~

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 44.0 psig.

The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.5% of primary containment air weight per day.

Leakage rate acceptance criteria are:

a. Primary Containment leakage rate acceptance criterion is less than or equal to 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are less than or equal to 0.60 L_a for the Type B and Type C tests and less than or equal to 0.75 L_a for Type A tests;

b. Air lock testing acceptance criteria are:

   1) Overall airlock leakage rate is less than or equal to 0.05 L_a when tested at greater than or equal to P_a.

   2) Seal leakage rate is less than or equal to 5 scf per hour when the gap between the door seals is pressurized to 10 psig.

The provisions of Specification 4.0.2 do not apply to the test frequencies specified in the Primary Containment Leakage Rate Testing Program.

The provisions of Specification 4.0.3 are applicable to the tests described in the Primary Containment Leakage Rate Testing Program.

h. Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

A change in the TS incorporated in the license; or

A change to the UFSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

d. Proposed changes that meet the criteria of b. above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

," Revision 3-A, dated July 2012, and the Limitations and Conditions specified in NEI 94-01, Revision 2-A, dated October 2008

g. Primary Containment Leakage Rate Testing Program

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 Leakage Test program," dated September 1995, as modified by the following exception to~~ NEI 94-01, ~~Rev. 0,~~ "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J"~~.~~

~~a. Section 9.2.3: The first Type A test performed after May 21, 1999 shall be performed no later than May 21, 2014.~~

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 44.0 psig.

The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.5% of primary containment air weight per day.

Leakage rate acceptance criteria are:

a. Primary Containment leakage rate acceptance criterion is less than or equal to 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are less than or equal to 0.60 L_a for the Type B and Type C tests and less than or equal to 0.75 L_a for Type A tests;

b. Air lock testing acceptance criteria are:

1) Overall airlock leakage rate is less than or equal to 0.05 L_a when tested at greater than or equal to P_a.

2) Seal leakage rate is less than or equal to 5 scf per hour when the gap between the door seals is pressurized to 10 psig.

The provisions of Specification 4.0.2 do not apply to the test frequencies specified in the Primary Containment Leakage Rate Testing Program.

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d. Proposed changes that meet the criteria of b. above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

," Revision 3-A, dated July 2012, and the Limitations and Conditions specified in NEI 94-01, Revision 2-A, dated October 2008

Attachment 3

Risk Assessment for LGS Regarding the ILRT (Type A) and DWBT Permanent Extension Request

RM DOCUMENTATION NO. **LG-LAR-18** **REV: 0** **PAGE NO. 1**

STATION: Limerick Generating Station (LGS)

UNIT(s) AFFECTED: 1 & 2

TITLE: Risk Assessment for LGS Regarding the ILRT (Type A) and DWBT Permanent Extension Request

SUMMARY:
LGS is pursuing a License Amendment Request (LAR) to permanently extend the Type A Integrated Leak Rate Test (ILRT) and Drywell Bypass Test (DWBT) to 15 years.

The purpose of this document is to provide an assessment of the risk associated with implementing a permanent extension of the LGS Unit 1 and Unit 2 containment ILRT and DWBT interval to 15 years.

This is a Category I Risk Management Document in accordance with ER-AA-600-1012 Risk Management Documentation [24], which requires independent review and approval, and ER-AA-600-1046 Risk Metrics – NOED and LAR [25].

[ ] Review required after periodic update

[X] Internal RM Documentation **[ ] External RM Documentation**

Electronic Calculation Data Files:
Microsoft Excel LimerickCalcs_ILRT-080118.xlsx, 08/01/2018, 3:33 PM 267 KB

Method of Review: [X] Detailed [ ] Alternate [ ] Review of External Document

This RM documentation supersedes: **N/A**

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1.0 OVERVIEW

The risk assessment associated with implementing a permanent extension of the LGS Unit 1 and Unit 2 Type A Integrated Leak Rate Test (ILRT) and Drywell Bypass Test (DWBT) interval to 15 years is described in this document.

1.1 PURPOSE

The purpose of this analysis is to provide an assessment of the risk associated with implementing a permanent extension of the LGS Units 1 and 2 containment Type A ILRT interval from ten years to fifteen years. The risk assessment follows the guidelines from NEI 94-01 [1], the methodology outlined in Electric Power Research Institute (EPRI) TR-104285 [2] as updated by the EPRI Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals (EPRI TR-1018243) [3], the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) findings and risk insights in support of a request for a plant's licensing basis as outlined in Regulatory Guide (RG) 1.174 [4], and 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 [5]. The format of this document is consistent with the intent of the Risk Impact Assessment Template for evaluating extended integrated leak rate testing intervals provided in the EPRI TR-1018243 [3].

This analysis also provides a risk assessment of extending the plant's Drywell to Suppression Chamber Bypass Leak Test (also referred to as the Drywell Bypass Test - DWBT) interval from 3 to 15 years. The DWBT risk assessment is performed in Appendix B separate from the Type A Test assessment in the main body of the calculation. The DWBT risk assessment is performed in accordance with the guidelines set forth in NEI 94-01 [1], the methodology used in EPRI TR-1018243 [3], and the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) findings and risk insights in support of a licensee request for changes to a plant's licensing basis, Reg. Guide 1.174 [4].

1.2 BACKGROUND

Revisions to 10CFR50, Appendix J (Option B) allow individual plants to extend the Integrated Leak Rate Test (ILRT) Type A surveillance testing requirements from three-in-ten years to at least once per 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 was less than the normal containment leakage of 1.0La (allowable leakage).

The basis for a 10-year test interval is provided in Section 11.0 of NEI 94-01, Revision 0, and was 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 [6], "Performance-Based Containment Leak Test Program," 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 EPRI Report TR-104285 [2].

The NRC report on performance-based leak testing, NUREG-1493 [6], 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 for a comparable BWR plant, that increasing the containment leak rate from the nominal 0.5 percent per day to 5 percent per day leads to a barely perceptible increase in total population exposure, and increasing the leak rate to 50 percent per day increases the total population exposure by less than 1 percent. Because ILRTs represent substantial resource expenditures, it is desirable to show that extending the ILRT interval will not lead to a substantial increase in risk from containment isolation failures to support a reduction in the test frequency for LGS. The current analysis is being performed to confirm these conclusions based on LGS specific PRA models and available data.

Earlier ILRT frequency extension submittals have used the EPRI TR-104285 [2] methodology to perform the risk assessment. In October 2008, EPRI 1018243 [3] was issued to develop a generic methodology for the risk impact assessment for ILRT interval extensions to 15 years using current performance data and risk informed guidance, primarily NRC Regulatory Guide 1.174 [4]. This more recent EPRI document considers the change in population dose, large early release frequency (LERF), and containment conditional failure probability (CCFP), whereas EPRI TR-104285 considered only the change in risk based on the change in population dose. This ILRT interval extension risk assessment for LGS U1 and U2 employs the EPRI 1018243 methodology, with the affected System, Structure, or Component (SSC) being the primary containment boundary. Addtionally, the methodology to evaluate the impact of concurrently extending the DWBT interval is performed consistent with previous one-time ILRT/DWBT extensions for BWR Mark II containment types including the Limerick one-time assessment [34], and Columbia [33], which have been approved by the NRC.

1.3 ACCEPTANCE CRITERIA

The acceptance guidelines in RG 1.174 [4] 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 1.0E-06 per reactor year and increases in large early release frequency (LERF) less than 1.0E-07 per reactor year. Note that a separate discussion in Section 5.8 of this risk assessment confirms that the CDF is not impacted by the proposed ILRT interval change for LGS. Therefore, since the Type A test has only a minimal impact on CDF for LGS, the relevant criterion is the change in LERF. RG 1.174 also defines "small" changes in LERF as below 1.0E-06 per reactor year, provided that the total LERF from all contributors (including external events) can be reasonably shown to be less than 1.0E-05 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) is also calculated to help ensure that the defense-in-depth philosophy is maintained.

With regard to population dose, examinations of NUREG-1493 [6] and Safety Evaluation Reports (SERs) for one-time interval extension (summarized in Appendix G of EPRI TR-1018243 [3]) indicate a range of incremental increases in population dose(1) that have been accepted by the NRC. The range of incremental population dose increases is from ≤0.01 to 0.2 person-rem/yr and 0.002 to 0.46% of the total accident dose. The total doses for the spectrum of all accidents (Figure 7-2 of NUREG-1493) result in health effects that are at least two orders of magnitude less than the NRC Safety Goal Risk. Given these perspectives, the NRC SER on this issue [7] defines a "small" increase in population dose as an increase of ≤ 1.0 person-rem per year, or ≤1 % of the total population dose (when compared against the baseline interval of 3 tests per 10 years), whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. This definition has been adopted for the LGS analysis.

The acceptance criteria are summarized below.

1. The estimated risk increase associated with permanently extending the ILRT/DWBT surveillance interval to 15 years must be demonstrated to be "small." (Note that Regulatory Guide 1.174 defines "very small" changes in risk as increases in CDF less than 1.0E-06 per reactor year and increases in LERF less than 1.0E-07 per reactor year. Since the type A ILRT test does not have a significant impact on CDF for LGS, the relevant risk metric is the change in LERF. Regulatory Guide 1.174 also defines "small" risk increase as a change in LERF of less than 1.0E-06 reactor year.) Therefore, a "small" change in risk for this application is defined as a LERF increase of less than 1.0E-06.
2. Per the NRC SE [7], a small increase in population dose is also 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.
3. In addition, the SE notes that 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 (typically about 1% or less, with the largest increase being 1.2%). This would require that the increase in CCFP be less than or equal to 1.5 percentage points.

(1) The one-time extensions assumed a large leak (EPRI class 3b) magnitude of 35La, whereas this analysis uses 100La.

2.0 METHODOLOGY

A simplified bounding analysis approach consistent with the EPRI methodology [3] is used for evaluating the change in risk associated with increasing the test interval to fifteen years. The analysis uses results from a Level 2 analysis of core damage scenarios from the current LGS PRA models of record [16, 17] and the subsequent containment responses to establish the various fission product release categories including the release size.

The six general steps of this assessment are as follows:

1. Quantify the baseline risk in terms of the frequency of events (per reactor year) for each of the eight containment release scenario types identified in the EPRI report [3].
2. Develop plant-specific population dose rates (person-rem per reactor year) for each of the eight containment release scenario types from plant specific consequence analyses.
3. Evaluate the risk impact (i.e., the change in containment release scenario type frequency and population dose) of extending the ILRT/DWBT interval to fifteen years.
4. Determine the change in risk in terms of Large Early Release Frequency (LERF) in accordance with RG 1.174 and compare this change with the acceptance guidelines of RG 1.174 [4].
5. Determine the impact on the Conditional Containment Failure Probability (CCFP)
6. Evaluate the sensitivity of the results to assumptions in the liner corrosion analysis and to variations in the fractional contributions of large isolation failures (due to liner breach) to LERF.

Furthermore,

- Consistent with the previous industry containment leak risk assessments, the LGS assessment uses population dose as one of the risk measures. The other risk measures used in the LGS assessment are the conditional containment failure probability (CCFP) for defense-in-depth considerations, and change in LERF to demonstrate that the acceptance guidelines from RG 1.174 are met.

- This evaluation for LGS uses ground rules and methods to calculate changes in the above risk metrics that are consistent with those outlined in the current EPRI methodology [3].

3.0 GROUND RULES

The following ground rules are used in the analysis:

- The LGS Level 1 and Level 2 internal events PRA models provide representative core damage frequency and release category frequency distributions to be utilized in this analysis. The technical adequacy of the PRA models is consistent with the requirements of Regulatory Guide 1.200 as relevant to this ILRT risk assessment. PRA adequacy is discussed in Appendix A of this document.
- It is appropriate to use the LGS internal events PRA model as a gauge to effectively describe the risk change attributable to the ILRT/DWBT extension. It is reasonable to assume that the impact from the ILRT/DWBT extension (with respect to percent increases in population dose) will not substantially differ if external events were to be included in the calculations; however, external events have been accounted for in the analysis based on the available information for LGS.
- Dose results for the containment failures modeled in the PRA can be characterized by information provided in NUREG/CR-4551 [8]. They are estimated by scaling the NUREG/CR-4551 results by population differences for Limerick compared to the NUREG/CR-4551 reference plant.
- Accident classes describing radionuclide release end states and their definitions are consistent with the EPRI methodology [3] and are summarized in Section 4.2.
- The representative containment leakage for Class 1 sequences is 1La. Class 3 accounts for increased leakage due to Type A inspection failures.
- The representative containment leakage for Class 3a is 10La and for Class 3b sequences is 100La, based on the recommendations in the latest EPRI report [3] and as recommended in the NRC SE [7] on this topic. It should be noted that this is more conservative than the earlier previous industry ILRT extension requests, which utilized 35La for the Class 3b sequences.
- Based on the EPRI methodology and the NRC SE, the Class 3b sequences are categorized as LERF and the increase in Class 3b sequences is used as a surrogate for the ΔLERF metric.
- The impact on population doses from containment bypass scenarios is not altered by the proposed ILRT extension, but is accounted for in the methodology as a separate entry for comparison purposes. Since the containment bypass contribution to population dose is fixed, no changes on 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.
- The use of the estimated 2050 population data [18] is appropriate for this analysis. Precise evaluations of the projected population would not significantly impact the quantitative results, nor would it change the conclusions.
- An evaluation of the risk impact of the ILRT on shutdown risk is addressed using the generic results from EPRI TR-105189 [9].
- The methodology to evaluate the impact of concurrently extending the DWBT interval is performed consistent with previous one-time ILRT/DWBT extensions for BWR Mark II containment types including the Limerick one-time assessment [34], and Columbia [33], which have been approved by the NRC.

4.0 INPUTS

This section summarizes the following:

- Section 4.1 – General resources available as input
- Section 4.2 – Plant specific inputs
- Section 4.3 - Impact of extension on detection of component failures that lead to leakage (small and large)
- Section 4.4 - impact of extension on detection of steel liner corrosion that leads to leakage

4.1 GENERAL RESOURCES AVAILABLE

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

1. NUREG/CR-3539 [10]
2. NUREG/CR-4220 [11]
3. NUREG-1273 [12]
4. NUREG/CR-4330 [13]
5. EPRI TR-105189 [9]
6. NUREG-1493 [6]
7. EPRI TR-104285 [2]
8. Calvert Cliffs liner corrosion analysis [5]
9. EPRI 1018243 [3]
10. NRC Final Safety Evaluation [7]

The 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 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 LLRT test intervals on at-power public risk. The eighth study addresses the impact of age-related degradation of the containment liners on ILRT evaluations. EPRI 1018243 complements the previous EPRI report and provides the results of an expert elicitation process to determine the relationship between pre-existing containment leakage probability and magnitude. Finally, the NRC Safety Evaluation (SE) documents the acceptance by the NRC of the proposed methodology with a few exceptions. These exceptions (associated with the ILRT Type A tests) were addressed in the Revision 2-A of NEI 94-01 (and maintained in Revision 3-A of NEI 94-01) and the final version of the updated EPRI report [3], which was used for this application.

<u>NUREG/CR-3539 [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 [14] 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 [11]</u>

NUREG/CR-4220 is a study performed by Pacific Northwest Laboratories for the NRC in 1985. The study reviewed over two thousand LERs, ILRT reports and other related records to calculate the unavailability of containment due to leakage. It assessed the "large" containment leak probability to be in the range of 1.0E-3 to 1.0E-2, with 5.0E-3 identified as the point estimate based on 4 events in 740 reactor years and conservatively assuming a one-year duration for each event.

<u>NUREG-1273 [12]</u>

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 [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 [9]

The EPRI study TR-105189 is useful to the ILRT test interval extension risk assessment because this EPRI study provides insight regarding the impact of containment testing on shutdown risk. This study performed 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 result of the study concluded that a small but measurable safety benefit (shutdown CDF reduced by 1.0E-8/yr to 1.0E-7/yr) is realized from extending the test intervals from 3 per 10 years to 1 per 10 years.

NUREG-1493 [6]

NUREG-1493 is the NRC's cost-benefit analysis for proposed alternatives to reduce containment leakage testing frequencies 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 [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 Integrated Leak Rate Test (ILRT) and Local Leak Rate Test (LLRT) test intervals on at-power public risk. This study combined Iindividual Plant Examination (IPE) Level 2 models with NUREG-1150 [15] Level 3 population dose models to perform the analysis. The study also used the approach of NUREG-1493 [6] in calculating the increase in pre-existing leakage probability due to extending the ILRT and LLRT test intervals.

EPRI TR-104285 used a simplified Containment Event Tree to subdivide representative core damage sequences into eight categories of containment response to a core damage accident:

1. Containment intact and isolated
2. Containment isolation failures due to support system or active failures
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 failure due to core damage accident phenomena
8. Containment bypass

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

> *"These study results show that 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..."*

Release Category Definitions

The EPRI methodology [2,3] defines the accident classes that may be used in the ILRT extension evaluation. These containment failure classes, reproduced in Table 4.1-1, are used in this analysis to determine the risk impact of extending the Containment Type A test interval as described in Section 5 of this report.

TABLE 4.1-1

EPRI [2] CONTAINMENT FAILURE CLASSIFICATIONS

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 IPEs) include 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 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 4 isolation failures, but is applicable to sequences involving Type C tests and their potential failures.
6	Containment isolation failures include 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.

TABLE 4.1-1

EPRI [2] CONTAINMENT FAILURE CLASSIFICATIONS

CLASS	DESCRIPTION
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.

Calvert Cliffs Liner Corrosion Analysis [5]

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

EPRI 1018243 [3]

This report presents a risk impact assessment for extending ILRT surveillance intervals to 15 years. This risk impact assessment complements the previous EPRI report, TR-104285 [2]. The earlier report considered changes to local leak rate testing intervals as well as changes to ILRT testing intervals. The original risk impact assessment [2] considers the change in risk based on population dose, whereas the revision [3] considers dose as well as large early release frequency (LERF) and conditional containment failure probability (CCFP). This report deals with changes to ILRT testing intervals and is intended to provide bases for supporting changes to industry and regulatory guidance on ILRT surveillance intervals.

The risk impact assessment using the Jeffrey's Non-Informative Prior statistical method is further supplemented with a sensitivity case using expert elicitation performed to address conservatisms. The expert elicitation is used to determine the relationship between pre-existing containment leakage probability and magnitude. The results of the expert elicitation process from this report are used as a separate sensitivity investigation for the LGS analysis presented here in Section 6.2.

NRC Safety Evaluation Report [7]

This SE documents the NRC staff's evaluation and acceptance of NEI TR 94-01, Revision 2, and EPRI Report No. 1009325, Revision 2, subject to the limitations and conditions identified in the SE and summarized in Section 4.0 of the SE. These limitations (associated with the ILRT Type A tests) were addressed in the Revision 2-A of NEI 94-01 which are also included in Revision 3-A of NEI 94-01 [1] and the final version of the updated EPRI report [3]. Additionally, the SE clearly defined the acceptance criteria to be used in future Type A ILRT extension risk assessments as delineated previously in the end of Section 1.3.

4.2 PLANT-SPECIFIC INPUTS

The LGS Unit 1 and Unit 2 specific information used to perform this ILRT interval extension risk assessment includes the following:

- Level 1 and Level 2 PRA model quantification results [16, 17]
- Population dose within a 50-mile radius for various release categories [18]

LGS Unit 1 and Unit 2 Internal Events Core Damage Frequencies

The current LGS Unit 1 and Unit 2 Internal Events PRA models of record are based on an event tree / linked fault tree model characteristic of the as-built, as-operated plant. Based on the results reported in Reference [16], the internal events Level 1 PRA core damage frequency (CDF) is 3.16E-06/yr for LGS Unit 1. Note that Unit 2 is very similar at 3.18E-06/yr. Table 4.2-1 provides the CDF results by accident class from the PRA Model Summary report [16] for Unit 1.

No substantive differences exist between the LGS Unit 1 and Unit 2 PRA models that are judged to affect the conclusions of the PRA. As such, no separate PRA quantification is conducted for Unit 2. Since the LGS PRA Unit 1 PRA results are judged representative of both Unit 1 and Unit 2, the ILRT/DWBT extension evaluation is considered applicable to both Unit 1 and Unit 2.

TABLE 4.2-1
SUMMARY OF LG117A CDF BY ACCIDENT SEQUENCE SUBCLASS

ACCIDENT CLASS DESIGNATOR	SUBCLASS	DEFINITION	LG117A MODEL (PER YR)
Class I	A	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high.	9.84E-07
	B	Accident sequences involving a loss of offsite power and loss of coolant inventory makeup.	9.18E-07
	C	Accident sequences involving a loss of coolant inventory induced by an ATWS sequence with containment intact.	7.10E-08
	D	Accident sequences involving a loss of coolant inventory makeup in which reactor pressure has been successfully reduced to 200 psi.	2.40E-07
	E	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high and DC power is unavailable.	2.29E-10
Class II	A	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	6.48E-07
	F	Class IIA and IIL except that the vent operates as designed; loss of makeup occurs at some time following vent initiation. Suppression pool saturated but intact.	2.05E-08
	L	Accident sequences involving a loss of containment heat removal with the RPV breached but no initial core damage; core damage induced post containment failure. (Note that this is grouped with Class IIA for transfer to the Level 2 model.)	

TABLE 4.2-1

SUMMARY OF LG117A CDF BY ACCIDENT SEQUENCE SUBCLASS

ACCIDENT CLASS DESIGNATOR	SUBCLASS	DEFINITION	LG117A MODEL (PER YR)
Class III (LOCA)	A	Accident sequences leading to core damage conditions initiated by vessel rupture where the containment integrity is not breached in the initial time phase of the accident.	8.61E-09
	B	Accident sequences initiated or resulting in small or medium LOCAs for which the reactor cannot be depressurized prior to core damage occurring.	3.39E-08
	C	Accident sequences initiated or resulting in medium or large LOCAs for which the reactor is a low pressure and no effective injection is available.	6.53E-09
	D	Accident sequences which are initiated by a LOCA or RPV failure and for which the vapor suppression system is inadequate, challenging the containment integrity with subsequent failure of makeup systems.	3.23E-09
Class IV (ATWS)	A	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially intact; core damage induced post containment failure.	2.17E-07
	L	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially breached; core damage induced post containment failure. (Note that this is grouped with Class IVA for transfer to the Level 2 model.)	
Class V	---	Unisolated LOCA outside containment.	6.94E-09
		Total	**3.16E-06**

LGS Internal Events Release Category Frequencies

The Level 2 Model that is used for LGS was developed to calculate the LERF contribution as well as the other release categories evaluated in the model. Thirteen (13) different release categories were developed in the LGS Level 2 PRA. These release categories represent radionuclide release severity and timing classification scheme shown in Table 4.2-2.

TABLE 4.2-2
LEVEL 2 END STATE BINS: RADIONUCLIDE RELEASE SEVERITY AND TIMING CLASSIFICATION SCHEME (SEVERITY, TIMING)(1)

RADIONUCLIDE RELEASE SEVERITY		RADIONUCLIDE RELEASE TIMING	
CLASSIFICATION CATEGORY	CS IODIDE % IN RELEASE	CLASSIFICATION CATEGORY	TIME OF INITIAL RELEASE(2) RELATIVE TO DECLARATION OF A GENERAL EMERGENCY
High (H)(4)	Greater than 10(4)	Late (L)	Greater than 24 hours
Moderate (M)	1 to 10	Intermediate (I)	E(3) to 24 hours
Low (L)	0.1 to 1	Early (E)	Less than E(3), (4) hours
Low-low (LL)	Less than 0.1		
No iodine (OK, Intact Containment)	Negligible		

Notes to Table 4.2-2:

(1) Thirteen (13) Level 2 End State Bins: H/E, H/I, H/L, M/E, M/I, M/L, L/E, L/I, L/L, LL/E, LL/I, LL/L, OK.

(2) The General Emergency declaration is accident sequence dependent and occurs when EALs are exceeded.

(3) Where E hours is less than the time when evacuation is effective (9 hours) for LGS.

(4) Consistent with NUREG/CR-6595 [23].

Table 4.2-3 summarizes the pertinent LGS Unit 1 results in terms of release category (timing and magnitude). The total Large Early Release Frequency (LERF) which corresponds to the H/E release category in Table 4.2-3 was found to be 2.09E-07/yr. The total release frequency is 2.82E-06/yr. With a total CDF of 3.16E-06/yr, this corresponds to an "OK" release limited to normal leakage of 3.45E-07/yr (after round-off).

TABLE 4.2-3
LGS LEVEL 2 PRA MODEL RELEASE CATEGORIES AND FREQUENCIES

CATEGORY	FREQUENCY/YR
Intact	3.45E-07
H/E – High Early (LERF)	2.09E-07
M/E – Medium Early	3.02E-07
L/E – Low Early	1.55E-07
LL/E – Low Low Early	0.00E+00
H/I – High Intermediate	1.61E-06
M/I – Medium Intermediate	6.51E-08
L/I – Low Intermediate	4.72E-07
LL/I – Low Low Intermediate	2.02E-09
H/L – High Late	0.00E+00
M/L – Medium Late	0.00E+00
L/L – Low Late	0.00E+00
LL/L – Low Low Late	0.00E+00
Total Release Frequency **(Cont. Intact Frequency not included)**	**2.82E-06**
Core Damage Frequency	**3.16E-06**

LGS Population Dose Information

The population dose is calculated by using data provided in NUREG/CR-4551 [8] and adjusting the results for Limerick. Each accident sequence was associated with an applicable collapsed Accident Progression Bin (APB) from NUREG/CR-4551. The collapsed APBs are characterized by 5 attributes related to the accident progression. Unique combinations of the 5 attributes result in a set of 10 bins that are relevant to the analysis. The definitions of the 10 collapsed APBs are provided in NUREG/CR-4551 and are reproduced in Table 4.2-4 for references purposes. Table 4.2-5 summarizes the calculated population dose associated with each APB from NUREG/CR-4551 for the Peach Bottom Atomic Power Station (PBAPS) reference plant.

Table 4.2-4

Collapsed Accident Progression Bin (APB) Descriptions [8]

Collapsed APB Number	Description
1	CD, VB, Early CF, WW Failure, RPV Pressure > 200 psi at VB Core damage occurs followed by vessel breach. The containment fails early in the wetwell (i.e., either before core damage, during core damage, or at vessel breach) and the RPV pressure is greater than 200 psi at the time of vessel breach (this means Direct Containment Heating (DCH) is possible).
2	CD, VB, Early CF, WW Failure, RPV Pressure < 200 psi at VB Core Damage occurs followed by vessel breach. The containment fails early in the wetwell (i.e., either before core damage, during core damage, or at vessel breach) and the RPV pressure is less than 200 psi at the time of vessel breach (this means DCH is not possible).
3	CD, VB, Early CF, DW Failure, RPV Pressure > 200 psi at VB Core damage occurs followed by vessel breach. The containment fails early in the drywell (i.e., either before core damage, during core damage, or at vessel breach) and the RPV pressure is greater than 200 psi at the time of vessel breach (this means DCH is possible).
4	CD, VB, Early CF, DW Failure, RPV Pressure < 200 psi at VB Core Damage occurs followed by vessel breach. The containment fails early in the drywell (i.e., either before core damage, during core damage, or at vessel breach) and the RPV pressure is less than 200 psi at the time of vessel breach (this means DCH is not possible).
5	CD, VB, Late CF, WW Failure, N/A Core Damage occurs followed by vessel breach. The containment fails late in the wetwell (i.e., after vessel breach during Molten Core-Concrete Interaction (MCCI)) and the RPV pressure is not important since, even if DCH occurred, it did not fail containment at the time it occurred.
6	CD, VB, Late CF, DW Failure, N/A Core Damage occurs followed by vessel breach. The containment fails late in the drywell (i.e., after vessel breach during MCCI) and the RPV pressure is not important since, even if DCH occurred, it did not fail containment at the time it occurred.
7	CD, VB, No CF, Vent, N/A Core Damage occurs followed by vessel breach. The containment never structurally fails, but is vented sometime during the accident progression. RPV pressure is not important (characteristic 5 is N/A) since, even if it occurred, DCH does not significantly affect the source term as the containment does not fail and the vent limits its effect.

Table 4.2-4
Collapsed Accident Progression Bin (APB) Descriptions [8]

Collapsed APB Number	Description
8	CD, VB, No CF, N/A, N/A Core damage occurs followed by vessel breach. The containment never fails structurally (characteristic 4 is N/A) and is not vented. RPV pressure is not important (characteristic 5 is N/A) since, even if it occurred, DCH did not fail containment. Some nominal leakage from the containment exists and is accounted for in the analysis so that while the risk will be small it is not completely negligible.
9	CD, No VB, N/A, N/A, N/A Core damage occurs but is arrested in time to prevent vessel breach. There are no releases associated with vessel breach or MCCI. It must be remembered, however, that the containment can fail due to overpressure or venting even if vessel breach is averted. Thus, the potential exists for some of the in-vessel releases to be released to the environment.
10	No CD, N/A, N/A, N/A, N/A Core damage did not occur. No in-vessel or ex-vessel release occurs. The containment may fail on overpressure or be vented. The RPV may be at high or low pressure depending on the progression characteristics. The risk associated with this bin is negligible.

Table 4.2-5
Calculation of PBAPS Population Dose at 50 Miles [8]

Collapsed Bin #	Fractional APB Contributions to Risk (MFCR) [(1)]	NUREG/CR-4551 Population Dose Risk at 50 miles (From a total of 7.9 person-rem/yr, mean) [(2)]	NUREG/CR-4551 Collapsed Bin Frequencies (per year) [(3)]	NUREG/CR-4551 Population Dose at 50 miles (Person-rem) [(4)]
1	0.021	0.1659	9.55E-08	1.74E+06
2	0.0066	0.05214	4.77E-08	1.09E+06
3	0.556	4.3924	1.48E-06	2.97E+06
4	0.226	1.7854	7.94E-07	2.25E+06
5	0.0022	0.01738	1.30E-08	1.34E+06
6	0.059	0.4661	2.04E-07	2.28E+06
7	0.118	0.9322	4.77E-07	1.95E+06
8	0.0005	0.00395	7.99E-07	4.94E+03
9	0.01	0.079	3.86E-07	2.05E+05
10	0	0	4.34E-08	0
Totals	**1.0**	**7.9**	**4.34E-6**	

---

(1) Mean Fractional Contribution to Risk from Table 5.2-3 of NUREG/CR-4551

(2) The total population dose risk at 50 miles from internal events in person-rem is provided in Table 5.1-1 of NUREG/CR-4551. The contribution for a given APB is the product of the total PDR50 and the fractional APB contribution.

(3) NUREG/CR-4551 provides the conditional probabilities of the collapsed APBs in Figure 2.5-6. These conditional probabilities are multiplied by the total internal CDF to calculate the collapsed APB frequency.

(4) Obtained from dividing the population dose risk shown in the third column of this table by the collapsed bin frequency shown in the fourth column of this table.

Population Estimate Methodology

The person-rem results in Table 4.2-5 can be used as an approximation of the dose for Limerick if it is corrected for the population surrounding Limerick. The total population within a 50-mile radius of Limerick is projected to be 9.51E+06 by the year 2050 [18]. The use of the 2050 estimate is judged to be sufficient to perform the permanent extension assessment.

This population value is compared to the population value that is provided in NUREG/CR-4551 in order to get a "Population Dose Factor" that can be applied to the APBs to get dose estimates for Limerick.

Total Limerick Population$_{50miles}$ = 9.51E+06
Peach Bottom Population from NUREG/CR-4551 = 3.02E+06
Population Dose Factor = 9.51E+06 / 3.02E+06 = 3.15

The difference in the doses at 50 miles is assumed to be in direct proportion to the difference in the population within 50 miles of each site. This does not take into account differences in meteorology data, detailed environmental factors or detailed differences in containment designs, but does provide a first-order approximation for Limerick of the population doses associated with each of the release categories from NUREG/CR-4551. This is considered adequate since the conclusions from this analysis will not be substantially affected by the actual dose values that are used.

Table 4.2-6 shows the results of applying the population dose factors to the NUREG/CR-4551 population dose results at 50 miles to obtain the adjusted population dose at 50 miles for Limerick.

Table 4.2-6
Calculation of Limerick Population Dose Risk at 50 Miles

Accident Progression Bin #	NUREG/CR-4551 Population Dose at 50 miles (Person-rem)	Bin Multiplier used to obtain Limerick Population Dose	Limerick Adjusted Population Dose at 50 miles (Person-rem)
1	1.74E+06	3.15	5.48E+06
2	1.09E+06	3.15	3.43E+06
3	2.97E+06	3.15	9.35E+06
4	2.25E+06	3.15	7.09E+06
5	1.34E+06	3.15	4.22E+06
6	2.28E+06	3.15	7.18E+06
7	1.95E+06	3.15	6.14E+06
8	4.94E+03	3.15	1.56E+04
9	2.05E+05	3.15	6.46E+05
10	0	3.15	0.00E+00

Application of Limerick PRA Model Results to NUREG/CR-4551 Level 3 Output

A factor related to the use of NUREG/CR-4551 in this evaluation is that the results of the Limerick PRA Level 2 model are not defined in the same terms as reported in NUREG/CR-4551. In order to use the Level 3 model presented in that document, it was necessary to apply the Limerick PRA Level 2 model results into a format which allowed for the scaling of the Level 3 results based on current Level 2 output. Finally, as mentioned above, the Level 3 results were modified to reflect the difference in the site demographics that exist between the two sites. This subsection provides a description of the process used to apply the Limerick PRA Level 2 model results into a form that can be used to generate Level 3 results using the NUREG/CR-4551 documentation.

The basic process that was pursued to obtain Level 3 results based on the Limerick Level 2 model and NUREG/CR-4551 was to define a useful relationship between the Level 2 and Level 3 results. Consequently, the end state characteristics of the Limerick Level 2 model were reviewed and assigned into one of the collapsed Accident Progression Bins (APBs) from NUREG/CR-4551.

The results from the thirteen release categories were previously shown in Table 4.2-3. For each of the non-zero release bins, a representative APB was assigned based on the timing and magnitude of the release associated with each bin. The results of the assignments are shown in Table 4.2-7.

Table 4.2-7
Assignments of Limerick Level 2 Results to APBs

Accident Progression Bin #	Brief Description (Refer to Table 4.2-3)	Limerick Adjusted Population Dose at 50 miles (Person-rem)	Assigned Limerick Level 2 Release Category
1	CD, VB, Early CF, WW Failure, RPV Pressure > 200 psi at VB	5.48E+06	50% of M/E Release (1.51E-07/yr)
2	CD, VB, Early CF, WW Failure, RPV Pressure < 200 psi at VB	3.43E+06	100% of L/E Release (1.54E-07/yr)
3	CD, VB, Early CF, DW Failure, RPV Pressure > 200 psi at VB	9.35E+06	100% of H/E Release (2.09E-07/yr)
4	CD, VB, Early CF, DW Failure, RPV Pressure < 200 psi at VB	7.09E+06	50% of M/E Release (1.51E-07/yr)
5	CD, VB, Late CF, WW Failure, N/A	4.22E+06	100% of L/I Rlease (4.72E-07/yr)
6	CD, VB, Late CF, DW Failure, N/A	7.18E+06	100% of H/I Release (1.61E-06/yr)
7	CD, VB, No CF, Vent, N/A	6.14E+06	100% of M/I Release (6.51E-08/yr)
8	CD, VB, No CF, N/A, N/A	1.56E+04	100% of Intact Release (3.45E-07/yr)
9	CD, No VB, N/A, N/A, N/A	6.45E+05	100% of LL/I Release (2.02E-09/yr)
10	No CD, N/A, N/A, N/A, N/A	0.00E+00	N/A

4.3 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 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 accounted for, the EPRI Class 3 accident class as defined in Table 4.1-1 is divided into two sub-classes representing small and large leakage failures. These subclasses are defined as Class 3a and Class 3b, respectively.

The probability of the EPRI Class 3a failures may be determined, consistent with the latest EPRI guidance [3], as the mean failure estimated from the available data (i.e., 2 "small" failures that could only have been discovered by the ILRT in 217 tests leads to a 2/217=0.0092 mean value). For Class 3b, consistent with latest available EPRI data, a non-informative prior distribution is assumed for no "large" failures in 217 tests (i.e., 0.5/(217+1) = 0.0023).

The EPRI methodology contains 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. This information includes a discussion of conservatisms in the quantitative guidance for delta LERF. EPRI describes ways to demonstrate that, using plant-specific calculations, the delta LERF is smaller than that calculated by the simplified method.

The methodology [3] 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 Limerick, as detailed in Section 5, means that the Class 2 and Class 8 sequences are subtracted from the CDF that is applied to Class 3b. To be consistent, the same change is made to the Class 3a CDF, even though these events are not considered LERF. Class 2 and Class 8 events refer to sequences with either large pre-existing containment isolation failures or containment bypass events. These sequences are already considered to contribute to LERF in the Limerick Level 2 PRA analysis.

Consistent with the EPRI methodology [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 yr / 2), and the average time that a leak could exist without detection for a ten-year interval is 5 years (10 yr / 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, given a 10-year vs. a 3-yr interval. Correspondingly, an extension of the ILRT interval to fifteen years can be estimated to lead to about a factor of 5.0 (7.5/1.5) increase in the non-detection probability of a leak.

<u>LGS Past ILRT Results</u>

The surveillance frequency for Type A testing in NEI 94-01 under option B criteria is at least once per ten years based on an acceptable performance history (i.e., two consecutive periodic Type A tests at least 24 months apart) where the calculated performance leakage rate was less than 1.0La, and in compliance with the performance factors in NEI 94-01, Section 11.3. Based on the successful completion of two consecutive ILRTs at LGS Unit 1 and Unit 2, the current ILRT interval is once per ten years. Note that the probability of a pre-existing leakage due to extending the ILRT interval is based on the industry-wide historical results as noted in the EPRI guidance document [3].

EPRI Methodology

This analysis uses the approach outlined in the EPRI methodology [3]. The six steps of the methodology are:

1. Quantify the baseline (three-year ILRT frequency) risk in terms of frequency per reactor year for the EPRI accident classes of interest.
2. Develop the baseline population dose (person-rem, from the plant PRA or IPE, or calculated based on leakage) for the applicable accident classes.
3. Evaluate the risk impact (in terms of population dose rate and percentile change in population dose rate) for the interval extension cases.
4. Determine the risk impact in terms of the change in LERF.
5. Determine the impact on the Conditional Containment Failure Probability (CCFP).
6. Evaluate the sensitivity of the results to assumptions in the liner corrosion analysis, and external event impacts.

The first three steps of the methodology deal with calculating the change in dose. The change in dose is the principal basis upon which the Type A ILRT interval extension was previously granted and is a reasonable basis for evaluating additional extensions. The fourth step in the methodology calculates the change in LERF and compares it to the guidelines in Regulatory Guide 1.174. Because the change in CDF for LGS is minimal, the change in LERF forms the quantitative basis for a risk informed decision per current NRC practice, namely Regulatory Guide 1.174. The fifth step of the methodology calculates the change in containment failure probability, referred to as the conditional containment failure probability, CCFP. The NRC has identified a CCFP of less than 1.5% as the acceptance criteria for extending the Type A ILRT test intervals as the basis for showing that the proposed change is consistent with the defense in depth philosophy [7]. As such, this step suffices as the remaining basis for a risk informed decision per Regulatory Guide 1.174. Step 6 takes into consideration the additional risk due to external events, and Step 6 investigates the impact on results due to varying the assumptions associated with the liner corrosion rate and failure to visually identify pre-existing flaws.

4.4 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 the methodology from the Calvert Cliffs liner corrosion analysis [5]. The Calvert Cliffs analysis was performed for a concrete cylinder and dome and a concrete basemat, each with a steel liner. The Limerick primary containment is a pressure-suppression BWR/Mark II containment type that also includes a steel-lined reinforced concrete structure.

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 walls
- 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>

1. Consistent with the Calvert analysis, a half failure is assumed for basemat concealed liner corrosion due to the lack of identified failures. (See Table 4.4-1, Step 1.)
2. The two corrosion events over a 5.5 year data period are used to estimate the liner flaw probability in the Calvert Cliffs analysis and are assumed to be applicable to the LGS containment analysis. These events, one at North Anna Unit 2 and one at Brunswick Unit 2, were initiated from the non-visible (backside) portion of the containment liner. It is noted that two additional events have occurred in recent years (based on a data search covering approximately 9 years documented in Reference [21]. In November 2006, the Turkey Point 4 containment building liner developed a hole when a sump pump support plate was moved. In May 2009, a hole approximately 3/8" by 1" in size was identified in the Beaver Valley 1

containment liner. For risk evaluation purposes, these two more recent events occurring over a 9 year period are judged to be adequately represented by the two events in the 5.5 year period of the Calvert Cliffs analysis incorporated in the EPRI guidance (See Table 4.4-1, Step 1).

3. 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 4.4-1, Steps 2 and 3). Sensitivity studies are included that address doubling this rate every two years and every ten years.
4. 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 region, and 0.11% (10% of the cylinder failure probability) for the basemat. These values were determined from an assessment of the containment fragility curve versus the ILRT test pressure. For LGS the containment failure probabilities are conservatively assumed to be 10% for the drywell and wetwall outer walls and 1% for the basemat. It is noted that since the basemat for the LGS Mark II containment is in the suppression pool, it is judged that failure of this area would not lead to LERF. Therefore the 1% probability is conservative. Sensitivity studies are included that increase and decrease the probabilities by an order of magnitude. (See Table 4.4-1, Step 4.)
5. 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 for the containment cylinder and head. To date, all liner corrosion events have been detected through visual inspection (See Table 4.4-1, Step 5). Sensitivity studies are included that evaluate total detection failure likelihood of 5% and 15%, respectively. Note that 100% of the basemat failures are assumed to be undetectable.
6. 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 4.4-1
STEEL LINER CORROSION BASE CASE

STEP	DESCRIPTION	CONTAINMENT CYLINDER, CONE AND HEAD	CONTAINMENT BASEMAT
1	**Historical Steel Liner Flaw Likelihood** Failure Data: Containment location specific (consistent with Calvert Cliffs analysis).	Events: 2 2/(70 * 5.5) = **5.2E-3**	Events: 0 (assume 0.5 failure) 0.5/(70 * 5.5) = **1.3E-3**
2	**Age Adjusted Steel Liner Flaw Likelihood** During 15-year interval, assume failure rate doubles every five years (14.9% increase per year). The average for 5th to 10th year is set to the historical failure rate (consistent with Calvert Cliffs analysis).	Year / Failure Rate 1 / 2.1E-3 avg 5-10 / 5.2E-3 15 / 1.4E-2 **15 year average = 6.27E-3**	Year / Failure Rate 1 / 5.1E-4 avg 5-10 / 1.3E-3 15 / 3.6E-3 **15 year average = 1.57E-3**
3	**Flaw Likelihood at 3, 10, and 15 years** Uses age adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every five years (consistent with Calvert Cliffs analysis – See Table 6 of Reference [5]).	**0.71% (1 to 3 years)** **4.06% (1 to 10 years)** **9.40% (1 to 15 years)** (Note that the Calvert Cliffs analysis presents the delta between 3 and 15 years of 8.7% to utilize in the estimation of the delta-LERF value. For this analysis, the values are calculated based on the 3, 10, and 15 year intervals.)	**0.18% (1 to 3 years)** **1.02% (1 to 10 years)** **2.35% (1 to 15 years)** (Note that the Calvert Cliffs analysis presents the delta between 3 and 15 years of 2.2% to utilize in the estimation of the delta-LERF value. For this analysis, the values are calculated based on the 3, 10, and 15 year intervals.)
4	**Likelihood of Breach in Containment Given Steel Liner Flaw** The failure probability of the containment cylinder and dome is assumed to be 10% (compared to 1.1% in the Calvert Cliffs analysis). The basemat failure probability is assumed to be a factor of ten less, 1% (compared to 0.11% in the Calvert Cliffs analysis).	**10%**	**1%**

TABLE 4.4-1

STEEL LINER CORROSION BASE CASE

STEP	DESCRIPTION	CONTAINMENT CYLINDER, CONE AND HEAD	CONTAINMENT BASEMAT
5	**Visual Inspection Detection Failure Likelihood** Utilize assumptions consistent with Calvert Cliffs analysis.	**10%** 5% failure to identify visual flaws plus 5% likelihood that the flaw is not visible (not through-cylinder but could be detected by ILRT) All events have been detected through visual inspection. 5% visible failure detection is a conservative assumption.	**100%** Cannot be visually inspected.
6	**Likelihood of Non-Detected Containment Leakage** (Steps 3 * 4 * 5)	**0.0071% (at 3 years)** =0.71% * 10% * 10% **0.0406% (at 10 years)** =4.06% * 10% * 10% **0.0940% (at 15 years)** =9.40% * 10% * 10%	**0.0018% (at 3 years)** =0.18% * 1% * 100% **0.0102% (at 10 years)** =1.02% * 1% * 100% **0.0235% (at 15 years)** =2.35% * 1% * 100%

The total likelihood of the corrosion-induced, non-detected containment leakage that is subsequently added to the EPRI Class 3b contribution is the sum of Step 6 for the containment cylinder and dome, and the containment basemat:

- At 3 years: 0.0071% + 0.0018% = 0.0089%
- At 10 years: 0.0406% + 0.0102% = 0.0508%
- At 15 years: 0.0940% + 0.0235% = 0.1175%

5.0 RESULTS

The application of the approach based on EPRI guidance [3] has led to the following results. The results are displayed according to the eight accident classes defined in the EPRI report. Table 5.0-1 lists these accident classes.

TABLE 5.0-1
ACCIDENT CLASSES

ACCIDENT CLASSES (CONTAINMENT RELEASE TYPE)	DESCRIPTION
1	Containment Intact
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 (Interfacing System LOCA)
CDF	**All CET End states (including very low and no release)**

The analysis performed examined the LGS specific accident sequences in which the containment remains intact or the containment is impaired. Specifically, the categorization 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 Class 1 sequences).
- 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 bellows leakage, if applicable. (EPRI Class 3 sequences).
- Core damage sequences in which containment integrity is impaired due to containment isolation failures of pathways left "opened" following a plant

post-maintenance test. (For example, a valve failing to close following a valve stroke test. (EPRI Class 6 sequences). Consistent with the EPRI Guidance, this class is not specifically examined since it will not significantly influence the results of this analysis.

- Accident sequences involving containment bypass (EPRI Class 8 sequences), large containment isolation failures (EPRI Class 2 sequences), and small containment isolation "failure-to-seal" events (EPRI Class 4 and 5 sequences) 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.

The steps taken to perform this risk assessment evaluation are as follows in sections 5.1 through 5.5:

Step 1 Quantify the base-line risk in terms of frequency per reactor year for each of the accident classes presented in Table 5.0-1.

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

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

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

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

Following Step 5, the results are summarized in section 5.6, external events are considered in Section 5.7 and the impact of containment overpressure is assessed in section 5.8.

It is noted that the calculations were generally performed using an electronic spreadsheet such that the presented numerical results may differslightly as compared to values calculated by hand.

5.1 STEP 1 – QUANTIFY THE BASE-LINE RISK IN TERMS OF FREQUENCY PER REACTOR YEAR

This step involves the review of the LGS Level 2 accident sequence frequency results. Table 5.1-1 relates EPRI class containment release scenarios to the various accident sequence categories. This mapping combined with the LGS dose (person-rem) results documented in Table 4.2-6 forms the basis for estimating the population dose for LGS.

For the assessment of ILRT impacts on the risk profile, the potential for pre-existing leaks is included in the model. (These events are represented by the Class 3 sequences in EPRI TR-1018243 [3]). 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 5.0-1 were developed for LGS based on Level 2 PRA inputs found in Section 4, determining the frequencies for Classes 3a and 3b, and then determining the remaining frequency for Class 1. Furthermore, 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 4.4. The eight containment release class frequencies were developed consistent with the definitions in Table 5.0-1 as described following Table 5.1-1.

Table 5.1-1 provides dose values for each EPRI scenario class. The dose values were developed in Section 4.2. The Level 2 Accident sequence bin(s) assigned to each EPRI Class are described under each containment release class discussion following Table 5.1-1. The methodology for determining the dose applied to EPRI Class 7 is further described under the paragraph heading "Class 7 Sequences".

TABLE 5.1-1

EPRI CLASS DOSE ASSIGNMENT FOR LGS

EPRI SCENARIO CLASS	ACCIDENT PROGRESSION BIN	RELEASE CATEGORY	DOSE (PERSON-REM)
1	APB-8	Intact	1.56E+04
2	APB-3	HE (non-ISLOCA)	9.35E+06
7	Weighted Average	Miscellaneous[1]	6.50E+06
Individual Contributors to Class 7 Weighted Average	APB-1	0.5*ME	5.48E+06
	APB-2	LE	3.43E+06
	APB-3	HE – EPRI 2 – EPRI 8	9.35E+06
	APB-4	0.5*ME	7.09E+06
	APB-5	LI	4.22E+06
	APB-6	HI	7.18E+06
	APB-7	MI	6.14E+06
	APB-9	LLI	6.46E+05
8	APB-3	HE (ISLOCA)	9.35E+06

Notes to Table 5.1-1:

(1) Given that multiple LGS discrete scenarios apply to the broader EPRI Class 7, the EPRI dose is based on a weighted average of the various release catgeory frequencies. The weighted average dose is developed in Table 5.1-2.

Class 1 Sequences

This group consists of all core damage accident progression bins for which the containment remains intact (modeled as Technical Specification Leakage). The frequency per year for these sequences is 3.09E-07/yr and is determined by subtracting all containment failure end states including the EPRI/NEI Class 3a and 3b frequency calculated below, from the total CDF. For this analysis, the associated maximum containment leakage for this group is 1La, consistent with an intact containment evaluation.

Class 1 = CDF – (EPRI Classes)

= 3.16E-06 – (9.78E-09 (Class 2) + 2.89E-08 (Class 3a) + 7.23E-09 (Class 3b) + 2.80E-06 (Class 7) + 6.94E-09 (Class 8))
= 3.09E-07/yr.

Class 2 Sequences

This group consists of large containment isolation failures. For LGS, containment isolation failure sequences resulting in a large early release are the following: IA-084, IBE-084, IBL-084, IC-084, ID-084, IIIB-043, and IIIC-043. The sum of the frequencies of these scenarios is 9.78E-09/yr.

Class 3 Sequences

This group represents pre-existing leakage in the containment structure (e.g., containment liner). The containment leakage for these sequences can be either small or large. In this analysis, a value of 10La was used for small pre-existing flaws and 100La for relatively large flaws.

The respective frequencies per year are determined as follows:

$PROB_{Class\_3a}$ = probability of small pre-existing containment liner leakage
= 0.0092 (see Section 4.3)

$PROB_{Class\_3b}$ = probability of large pre-existing containment liner leakage
= 0.0023 (see Section 4.3)

As described in Section 4.3, additional consideration is made to not apply these failure probabilities to those cases that are already considered LERF scenarios (i.e., the Class 2 and Class 8 contributions). Note that some portion of the EPRI Class 7 frequency also represents LERF scenarios, but these are conservatively not subtracted from that portion of CDF eligible for EPRI Class 3. The adjustment to exclude EPRI Class 2 and Class 8 is made on the frequency information as shown below:

Class_3a = 0.0092 * [CDF – (Class 2 + Class 8)]
= 0.0092 * [3.16E-06 – (9.78E-09 + 6.94E-09)]
= 2.89E-08/yr

Class_3b = 0.0023 * [CDF – (Class 2 + Class 8)]
= 0.0023 * [3.16E-06 – (9.78E-09 + 6.94E-09)]
= 7.23E-09/yr

For this analysis, the associated containment leakage for Class 3a is 10La and 100La for Class 3b, which is consistent with the latest EPRI methodology [3] and the NRC SE [7].

Class 4 Sequences

This group represents containment isolation failure-to-seal of Type B test components. 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 this analysis.

Class 5 Sequences

This group represents containment isolation failure-to-seal of Type C test components. Because these 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.

Class 6 Sequences

This group is similar to Class 2. These are sequences that involve core damage with a failure-to-seal containment leakage due to failure to isolate the containment. These sequences are dominated by misalignment of containment isolation valves following a test/maintenance evolution. Consistent with the EPRI guidance, this accident class is not explicitly considered since it has a negligible impact on the results.

Class 7 Sequences

This group consists of all core damage accident progression bins in which containment failure induced by severe accident phenomena occurs. Note that containment failure is not induced for containment bypass (BOC and ISLOCA) (EPRI Class 8) and isolation failure (EPRI Class 2) sequences as these are either the initiating event or a plant condition, existing at the time of the initiating event. For this analysis, the associated radionuclide releases are based on the application of the Level 2 end states from the LGS release category evaluation as described in Section 4.2. The Class 7 Sequences are all Level 2 release categories except containment intact EPRI Class 1, the containment bypass (EPRI Class 8) and isolation failure (EPRI Class 2) sequences leading to a large early release. The failure frequency and population dose for each specific release category is shown below in Table 5.1-2. The total release frequency and total dose are then used to determine a weighted average person-rem. The resulting weighted average person-rem is the representative EPRI Class 7 dose in the subsequent analysis. Note that the total frequency and dose associated from this EPRI class does not change as part of the ILRT extension request.

TABLE 5.1-2

ACCIDENT CLASS 7 FAILURE FREQUENCIES AND POPULATION DOSES (LGS BASE CASE LEVEL 2 MODEL)

ACCIDENT PROGRESSION BIN	RELEASE CATEGORY	RELEASE FREQUENCY / YR(1)	POPULATION DOSE (50 MILES) PERSON-REM(2)	POPULATION DOSE RISK (50 MILES) (PERSON-REM / YR)(3)
APB-1	50% of ME	1.51E-07	5.48E+06	8.27E-01
APB-2	LE	1.54E-07	3.43E+06	5.30E-01
APB-3	HE – (Class 2 + Class 8)	1.92E-07	9.35E+06	1.80E+00
APB-4	50% of ME	1.51E-07	7.09E+06	1.07E+00
APB-5	LI	4.72E-07	4.22E+06	1.99E+00
APB-6	HI	1.61E-06	7.18E+06	1.16E+01
APB-7	MI	6.51E-08	6.14E+06	4.00E-01
APB-9	LLI	2.02E-09	6.46E+05	1.30E-03
Class 7 Total		**2.80E-06**	**6.50E+06(4)**	**1.818E+01**

Notes to Table 5.1-2:

(1) Release Frequency values obtained from Table 4.2-3.

(2) Population dose values obtained from Table 4.2-7.

(3) Obtained by multiplying the Release Frequency per year by the Population Dose Person-Rem value. Calculations were performed using more than 3 significant figures. Therefore, figures may differ in the 3rd digit if multiplying the figures shown above.

(4) The weighted average population dose for Class 7 is obtained by dividing the total population dose risk by the total release frequency.

Class 8 Sequences

This group represents sequences where containment bypass occurs. For this analysis, the frequency is determined from release categories Break Outside Containment (BOC) and ISLOCA Level 2 results. BOC and ISLOCA sequences contribute 1.23E-09/yr and 5.71E-09/yr respectively. The sum of each of these contributions is 6.94E-09/yr (listed in Table 4.2-1 for Accident Class V sequences).

Summary of Accident Class Frequencies

In summary, the accident sequence frequencies that can lead to release of radionuclides to the public have been derived in a manner consistent with the definition of accident classes defined in EPRI 1018243 [3] and are shown in Table 5.1-3 by accident class.

TABLE 5.1-3
RADIONUCLIDE RELEASE FREQUENCIES AS A FUNCTION OF ACCIDENT CLASS (LGS BASE CASE)

ACCIDENT CLASSES (CONTAINMENT RELEASE TYPE)	DESCRIPTION	FREQUENCY (PER RX-YR)
1	No Containment Failure	3.09E-07
2	Large Isolation Failures (Failure to Close)	9.78E-09
3a	Small Isolation Failures (liner breach)	2.89E-08
3b	Large Isolation Failures (liner breach)	7.23E-09
4	Small Isolation Failures (Failure to seal –Type B)	N/A
5	Small Isolation Failures (Failure to seal—Type C)	N/A
6	Other Isolation Failures (e.g., dependent failures)	N/A
7	Failures Induced by Phenomena (Early and Late)	2.80E-06
8	Bypass (Interfacing System LOCA)	6.94E-09
CDF	**All CET End states (including very low and no release)**	**3.16E-06**

5.2 STEP 2 – DEVELOP PLANT-SPECIFIC PERSON-REM DOSE (POPULATION DOSE) PER REACTOR YEAR

Plant-specific release analyses were performed to estimate the person-rem doses to the population within a 50-mile radius from the plant. The releases are based on information provided by NUREG/CR-4551 with adjustments made for the site demographic differences compared to the reference plant as described in Section 4.2, and summarized in Table 4.2-7. The results of applying these releases to the EPRI/NEI containment failure classification defined in Table 4.1-1 are as follows:

Class 1	=	1.56E+04 person-rem (at 1.0L_a) (1)
Class 2	=	9.35E+06(2)
Class 3a	=	1.56E+04 person-rem x 10L_a = 1.56E+05 person-rem (3)
Class 3b	=	1.56E+04 person-rem x 100L_a = 1.56E+06 person-rem (3)
Class 4	=	Not analyzed
Class 5	=	Not analyzed
Class 6	=	Not analyzed
Class 7	=	6.50E+06 person-rem (4)
Class 8	=	9.35E+06 person-rem (5)

(1) The Class 1, containment intact sequences, dose is assigned from the APB #8 (No CF, No Vent) from the NUREG/CR-4551 adjusted dose for Limerick as shown in Table 4.2-6.

(2) The Class 2, containment isolation failures, dose is approximated from APB #3 (VB, Early DW, Hi Press) from Table 4.2-7.

(3) The Class 3a and 3b dose are related to the leakage rate as shown.

(4) The Class 7 dose is assigned from the weighted average dose calculated from the APBs from Table 4.2-7 as detailed in Table 5.1-2 above.

(5) Class 8 sequences involve containment bypass failures; as a result, the person-rem dose is not based on normal containment leakage. As an approximation, the releases for this class are assigned from APB #3 from Table 4.2-7 which is the largest dose.

In summary, the population dose estimates derived for use in the risk evaluation per the EPRI methodology [3] containment failure classifications are provided in Table 5.2-1.

TABLE 5.2-1

LGS POPULATION DOSE ESTIMATES FOR POPULATION WITHIN 50 MILES

ACCIDENT CLASSES (CONTAINMENT RELEASE TYPE)	REPRESENTATIVE ACCIDENT SEQUENCE	DESCRIPTION	PERSON-REM (50 MILES)
1	Containment Intact	No Containment Failure (1 La)	1.56E+04
2	H/E	Large Isolation Failures (Failure to Close)	9.35E+06
3a	$10L_a$	Small Isolation Failures (liner breach)	1.56E+05
3b	$100L_a$	Large Isolation Failures (liner breach)	1.56E+06
4	N/A	Small Isolation Failures (Failure to seal –Type B)	NA
5	N/A	Small Isolation Failures (Failure to seal—Type C)	NA
6	N/A	Other Isolation Failures (e.g., dependent failures)	NA
7	See Table 5.1-2 (All releases except isolation, and bypass sequences)	Failures Induced by Phenomena (Early and Late)	6.50E+06
8	H/E	Bypass (BOC and Interfacing System LOCA)	9.35E+06

The above dose estimates, when combined with the frequency results presented in Table 5.1-3, yield the LGS baseline mean consequence measures for each accident class. These results are presented in Table 5.2-2.

TABLE 5.2-2

LGS ANNUAL DOSE AS A FUNCTION OF ACCIDENT CLASS; CHARACTERISTIC OF CONDITIONS FOR 3 IN 10 YEAR ILRT FREQUENCY

ACCIDENT CLASSES (CONT. RELEASE TYPE)	DESCRIPTION	PERSON-REM (0-50 MILES)	EPRI METHODOLOGY		EPRI METHODOLOGY PLUS CORROSION		CHANGE DUE TO CORROSION (PERSON-REM/YR) (1)
			FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	
1	Containment Intact (2)	1.56E+04	3.09E-07	4.81E-03	3.09E-07	4.81E-03	-4.34E-06
2	Large Isolation Failures (Failure to Close)	9.35E+06	9.78E-09	9.15E-02	9.78E-09	9.15E-02	--
3a	Small Isolation Failures (liner breach)	1.56E+05	2.89E-08	4.50E-03	2.89E-08	4.50E-03	--
3b	Large Isolation Failures (liner breach)	1.56E+06	7.23E-09	1.13E-02	7.51E-09	1.17E-02	4.34E-04
7	Failures Induced by Phenomena (Early and Late)	6.50E+06	2.80E-06	1.818E+01	2.80E-06	1.818E+01	--
8	Containment Bypass (Interfacing System LOCA)	9.35E+06	6.94E-09	6.49E-02	6.94E-09	6.49E-02	--
CDF	**All CET end states**		**3.16E-06**	**18.356**	**3.16E-06**	**18.356**	**4.30E-04**

Notes to Table 5.2-2:

(1) Only release Classes 1 and 3b are affected by the corrosion analysis. During the ILRT interval, the failure rate is assumed to double every five years. The additional frequency added to Class 3b is subtracted from Class 1 and the population dose rates are recalculated. This results in a small reduction to the Class 1 dose rate and an increase to the Class 3b dose rate.

(2) Characterized as 1L_a release magnitude consistent with the derivation of the ILRT non-detection failure probability for ILRTs. Release classes 3a and 3b include failures of containment to meet the Technical Specification leak rate.

5.3 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 ten-year value to fifteen-years. To do this, an evaluation must first be made of the risk associated with the ten-year interval since the base case applies to a 3-year interval (i.e., a simplified representation of a 3-in-10 year 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 3b sequences is impacted. The risk contribution is changed based on the EPRI guidance as described in Section 4.3 by a factor of 3.33 compared to the base case values. The results of the calculation for a 10-year interval are presented in Table 5.3-1.

Risk Impact Due to 15-Year Test Interval

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 not detecting a leak in Classes 3a and 3b. For this case, the value used in the analysis is a factor of 5.0 compared to the 3-year interval value, as described in Section 4.3. The results for this calculation are presented in Table 5.3-2.

TABLE 5.3-1

LGS ANNUAL DOSE AS A FUNCTION OF ACCIDENT CLASS; CHARACTERISTIC OF CONDITIONS FOR 1 IN 10 YEAR ILRT FREQUENCY

ACCIDENT CLASSES (CONT. RELEASE TYPE)	DESCRIPTION	PERSON-REM (0-50 MILES)	EPRI METHODOLOGY		EPRI METHODOLOGY PLUS CORROSION		CHANGE DUE TO CORROSION (PERSON-REM/YR)(1)
			FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	
1	Containment Intact (2)	1.56E+04	2.25E-07	3.50E-03	2.23E-07	3.47E-03	-2.48E-05
2	Large Isolation Failures (Failure to Close)	9.35E+06	9.78E-09	9.15E-02	9.78E-09	9.15E-02	--
3a	Small Isolation Failures (liner breach)	1.56E+05	9.63E-08	1.50E-02	9.63E-08	1.50E-02	--
3b	Large Isolation Failures (liner breach)	1.56E+06	2.41E-08	3.75E-02	2.57E-08	3.99E-02	2.48E-03
7	Failures Induced by Phenomena (Early and Late)	6.50E+06	2.80E-06	1.818E+01	2.80E-06	1.818E+01	--
8	Containment Bypass (Interfacing System LOCA)	9.35E+06	6.94E-09	6.49E-02	6.94E-09	6.49E-02	--
CDF	**All CET end states**		**3.16E-06**	**18.391**	**3.16E-06**	**18.393**	**2.46E-03**

Notes to Table 5.3-1:

(1) Only release Classes 1 and 3b are affected by the corrosion analysis. During the ILRT interval, the failure rate is assumed to double every five years. The additional frequency added to Class 3b is subtracted from Class 1 and the population dose rates are recalculated. This results in a small reduction to the Class 1 dose rate and an increase to the Class 3b dose rate.

(2) Characterized as 1L_a release magnitude consistent with the derivation of the ILRT non-detection failure probability for ILRTs. Release classes 3a and 3b include failures of containment to meet the Technical Specification leak rate.

TABLE 5.3-2

LGS ANNUAL DOSE AS A FUNCTION OF ACCIDENT CLASS; CHARACTERISTIC OF CONDITIONS FOR 1 IN 15 YEAR ILRT FREQUENCY

ACCIDENT CLASSES (CONT. RELEASE TYPE)	DESCRIPTION	PERSON-REM (0-50 MILES)	EPRI METHODOLOGY		EPRI METHODOLOGY PLUS CORROSION		CHANGE DUE TO CORROSION (PERSON-REM/YR) (1)
			FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	
1	Containment Intact (2)	1.56E+04	1.65E-07	2.56E-03	1.61E-07	2.50E-03	-5.75E-05
2	Large Isolation Failures (Failure to Close)	9.35E+06	9.78E-09	9.15E-02	9.78E-09	9.15E-02	--
3a	Small Isolation Failures (liner breach)	1.56E+05	1.45E-07	2.25E-02	1.45E-07	2.25E-02	--
3b	Large Isolation Failures (liner breach)	1.56E+06	3.61E-08	5.62E-02	3.98E-08	6.20E-02	5.75E-03
7	Failures Induced by Phenomena (Early and Late)	6.50E+06	2.80E-06	1.818E+01	2.80E-06	1.818E+01	--
8	Containment Bypass (Interfacing System LOCA)	9.35E+06	6.94E-09	6.49E-02	6.94E-09	6.49E-02	--
CDF	**All CET end states**		**3.16E-06**	**18.416**	**3.16E-06**	**18.422**	**5.69E-03**

Notes to Table 5.3-2:

(1) Only release Classes 1 and 3b are affected by the corrosion analysis. During the 15-year interval, the failure rate is assumed to double every five years. The additional frequency added to Class 3b is subtracted from Class 1 and the population dose rates are recalculated. This results in a small reduction to the Class 1 dose rate and an increase to the Class 3b dose rate.

(2) Characterized as $1L_a$ release magnitude consistent with the derivation of the ILRT non-detection failure probability for ILRTs. Release classes 3a and 3b include failures of containment to meet the Technical Specification leak rate.

5.4 STEP 4 – DETERMINE THE CHANGE IN RISK IN TERMS OF LARGE EARLY RELEASE FREQUENCY

Regulatory Guide 1.174 provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines very small changes in risk as resulting in increases of core damage frequency (CDF) below 1E-06/yr and increases in LERF below 1E-07/yr, and small changes in LERF as below 1E-06/yr. Because the ILRT for LGS has only a minor impact on CDF, the relevant metric is LERF.

For LGS, 100% of the frequency of Class 3b sequences can be used as a conservative first-order estimate to approximate the potential increase in LERF from the ILRT interval extension (consistent with the EPRI guidance methodology and the NRC SE). Based on the original 3-in-10 year test interval assessment from Table 5.2-2, the Class 3b frequency is 7.51E-09/yr, which includes the corrosion effect of the containment liner. Based on a ten-year test interval from Table 5.3-1, the Class 3b frequency is 2.57E-08/yr; and, based on a fifteen-year test interval from Table 5.3-2, it is 3.98E-08/yr. 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 (including corrosion effects) is 3.23E-08/yr. Similarly, the increase in LERF due to increasing the interval from 10 to 15 years (including corrosion effects) is 1.42E-08/yr. As can be seen, even with the conservatisms included in the evaluation (per the EPRI methodology), the estimated change in LERF is well within Region III of Figure 4 of Reference [4] (i.e., the acceptance criteria for very small changes in LERF) when comparing the 15 year results to the original 3-in-10 year requirement.

5.5 STEP 5 – DETERMINE THE IMPACT ON THE CONDITIONAL CONTAINMENT FAILURE PROBABILITY

Another parameter that can provide input into the decision-making process is the change in the conditional containment failure probability (CCFP). The change in CCFP is indicative of the effect of the ILRT on all radionuclide releases, not just LERF. The CCFP can be calculated from the results of this analysis. One of the difficult aspects of this calculation is providing a definition of the "failed containment." In this assessment, the

CCFP is defined such that containment failure includes all radionuclide release end states other than the intact state and, consistent with the EPRI guidance, the small isolation failures (Class 3a). The conditional part of the definition is conditional given a severe accident (i.e., core damage).

The change in CCFP can be calculated by using the method specified in the EPRI methodology [3]. The NRC SE has noted a change in CCFP of <1.5% as the acceptance criterion to be used as the basis for showing that the proposed change is consistent with the defense-in-depth philosophy. Table 5.5-1 shows the CCFP values that result from the assessment for the various testing intervals including corrosion effects in which the flaw rate is assumed to double every five years.

TABLE 5.5-1

LGS ILRT CONDITIONAL CONTAINMENT FAILURE PROBABILITIES

CCFP 3 IN 10 YRS	CCFP 1 IN 10 YRS	CCFP 1 IN 15 YRS	$\Delta CCFP_{15-3}$	$\Delta CCFP_{15-10}$
89.31%	89.88%	90.33%	1.02%	0.45%

Note to Table 5.5-1:

CCFP = [1 – (Class 1 frequency + Class 3a frequency)/CDF] x 100%

The change in CCFP of about 1% as a result of extending the test interval to 15 years from the original 3-in-10 year requirement is judged to be relatively insignificant, and is less than the NRC SE acceptance criteria of < 1.5%.

5.6 SUMMARY OF INTERNAL EVENTS RESULTS

Table 5.6-1 summarizes the internal events results of this ILRT extension risk assessment for LGS. The results between the 3-in-10 year interval and the 15 year interval compared to the acceptance criteria are then shown in Table 5.6-2, and it is demonstrated that the acceptance criteria are met.

TABLE 5.6-1

LGS ILRT CASES: BASE, 3 TO 10, AND 3 TO 15 YR EXTENSIONS (INCLUDING AGE ADJUSTED STEEL LINER CORROSION LIKELIHOOD)

		BASE CASE 3 IN 10 YEARS		EXTEND TO 1 IN 10 YEARS		EXTEND TO 1 IN 15 YEARS	
EPRI CLASS	**DOSE PER-REM**	**CDF (1/YR)**	**PERSON-REM/YR**	**CDF (1/YR)**	**PERSON-REM/YR**	**CDF (1/YR)**	**PERSON-REM/YR**
1	1.56E+04	3.09E-07	4.81E-03	2.23E-07	3.47E-03	1.61E-07	2.50E-03
2	9.35E+06	9.78E-09	9.15E-02	9.78E-09	9.15E-02	9.78E-09	9.15E-02
3a	1.56E+05	2.89E-08	4.50E-03	9.63E-08	1.50E-02	1.45E-07	2.25E-02
3b	1.56E+06	7.51E-09	1.17E-02	2.57E-08	3.99E-02	3.98E-08	6.20E-02
7	6.50E+06	2.80E-06	1.818E+01	2.80E-06	1.818E+01	2.80E-06	1.818E+01
8	9.35E+06	6.94E-09	6.49E-02	6.94E-09	6.49E-02	6.94E-09	6.49E-02
Total		**3.16E-06**	**18.356**	**3.16E-06**	**18.393**	**3.16E-06**	**18.422**
ILRT Dose Rate (person-rem/yr) from 3a and 3b		1.62E-02		5.49E-02		8.45E-02	
Delta Total Dose Rate(1)	From 3 yr	---		3.74E-02		6.60E-02	
	From 10 yr	---		---		2.86E-02	
3b Frequency (LERF)		7.51E-09		2.57E-08		3.98E-08	
Delta 3b LERF	From 3 yr	---		1.82E-08		3.23E-08	
	From 10 yr	---		---		1.42E-08	
CCFP %		89.31%		89.88%		90.33%	
Delta CCFP %	From 3 yr	---		0.57%		1.02%	
	From 10 yr	---		---		0.45%	

Note to Table 5.6-1:

(1) The overall difference in total dose rate is less than the difference of only the 3a and 3b categories between two testing intervals. This is due to the fact that the Class 1 person-rem/yr decreases when extending the ILRT frequency.

TABLE 5.6-2

LGS ILRT EXTENSION COMPARISON TO ACCEPTANCE CRITERIA

Figure of Merit ->	ΔLERF	ΔPerson-rem/yr	ΔCCFP
Results (3/10yrs to 1/15yrs)	3.23E-8/yr	6.60E-02/yr (0.36%)	1.02%
Acceptance Criteria per NRC SE [7]	<1.0E-6/yr	<1.0 person-rem/yr or <1.0%	<1.5%

5.7 EXTERNAL EVENTS CONTRIBUTION

Since the risk acceptance guidelines in RG 1.174 are intended for comparison with a full-scope assessment of risk, including internal and external events, a bounding analysis of the potential impact from external events is presented here.

5.7.1 Fire Risk

The LGS Fire PRA (FPRA) peer review was performed November 2011 using the NEI 07-12 Fire PRA peer review process [26], the ASME PRA Standard, ASME/ANS RA-Sa-2009 [28] and Regulatory Guide 1.200, Rev. 2 [30]. The purpose of this review was to establish the technical adequacy of the FPRA for the spectrum of potential risk-informed plant licensing applications for which the FPRA may be used. The 2011 LGS FPRA peer review was a full-scope review of all of the technical elements of the LGS at-power FPRA against all technical elements in Part 4 of the ASME/ANS PRA Standard, including the referenced internal events supporting requirements (SRs). The peer review noted a number of facts and observations (F&Os). The latest Fire PRA model (LG113A2F0) was approved as an application specific model for Unit 1 in May 2016 [31] to address many of the original peer review findings. The Unit 1 CDF is 1.05E-05/yr and LERF is 1.84E-07/yr. The Unit 2 results are similar (i.e., the Unit 2 CDF is 1.06E-5/yr and the Unit 2 LERF is 2.56E-07/yr).

Additonally in July 2016 a review of the FPRA peer review findings and the resolutions was performed by an independent review team [32]. The independent review team concluded that 14 of the findings were either partially resolved or still open. An additional six findings were not assessed by the independent review team since they were assessed as being open prior to the independent review. The disposition of those findings for this application is discussed in Appendix A.

For this analysis, the higher reported FPRA CDF value from Unit 2 (1.06E-5/yr) is used to support the risk calculations, which is approximately a factor of 3.3 higher than the current internal events CDF value of 3.16E-06/yr. The higher Unit 2 LERF value of 2.56E-7/yr will also be used for this assessment.

5.7.2 Seismic Risk

Bounding seismic CDF values from the NRC have been made public as part of the development of a generic issue report. Table D-1 of Risk Assessment for NRC GI-199 [27] lists the postulated core damage frequencies using the updated 2008 USGS Seismic Hazard Curves. The weakest link model using the curve for LGS resulted in a CDF of 5.3E-05/yr and is the highest CDF presented in the Risk Assessment for NRC GI-199 for LGS. It should be noted, however, that this seismic CDF estimate was based on a PGA fragility (plant level) HCLPF value of 0.15g as noted in Table C-2 of GI-199 [27]. The more realisitc limiting seismic capacity component has a high confidence of low probability of failure (HCLPF) value of 0.30g PGA. The basis for this value is as follows. The LGS IPEEE [22] assessed LGS structures, systems and components (SSCs) associated with LGS SMA success paths to a review level earthquake (RLE) value of 0.15g PGA for Electric Power Research Institute (EPRI) Seismic Margin Assessment (SMA) reduced-scope plants. However, as stated in the NRC's safety evaluation report [35] associated with the LGS IPEEE, "subsequent to the submittal, the licensee provided additional information [via responses to NRC Requests for Additional Information (RAIs)] which, upon review, indicated that all SSCs on the [SMA] success path component list (SPCL) have a capacity of at least 0.3g PGA or are acceptable as-is." Therefore, a limiting HCLPF value of 0.30g PGA is a more appropriate plant level HCLPF value to utilize. If this value is used combined with the latest hazard curve data, the estimated seismic CDF developed in support of potential Risk-Informed Completion Times at Limerick [36] is more than an order of magnitude less than that reported for

Limerick in GI-199. In any event, half of the reported GI-199 value will be utilized to clearly bound the potential impact from external events on this application. This revised seismic CDF estimate of 2.65E-05/yr is a factor of 8.4 higher than the FPIE CDF (2.65E-05/yr ÷ 3.16E-06/yr). Assuming that the ratio of the seismic LERF to the FPIE LERF is that same as the ratio of the CDF values, the seismic LERF can be approximated by multiplying the FPIE LERF of 2.07E-07/yr by 8.4. The result of 1.75E-06/yr is used in this analysis to represent the seismic LERF.

5.7.3 Other External Event Risk

External hazards were evaluated in the LGS Individual Plant Examination of External Events (IPEEE) submittal [22] in response to the NRC IPEEE Program (Generic Letter 88-20, Supplement 4) [20]. The IPEEE Program was a one-time review of external hazard risk and was limited in its purpose to the identification of potential plant vulnerabilities and the understanding of associated severe accident risks.

In addition to internal fires and seismic events, the LGS IPEEE Submittal analyzed a variety of other external hazards including, but not limited to:

- Aircraft impact
- External flooding
- Pipeline accidents
- Military and industrial facilities accidents
- Transportation accidents
- Release of chemicals in onsite storage
- High winds and tornadoes

The IPEEE analysis concluded that the other external hazards were insignificant contributors to plant risk. A more recent evaluation [37] confirmed that conclusion in support of the 50.69 categorization submittal for Limerick.

Based on the other external events being low risk contributors and the fact that the ILRT extension would not significantly change the risk from these types of events, the increase in the LGS other external events risk due to the ILRT extension is much less than that calculated for internal events, and is considered to be bounded by the very conservative assumed seismic contribution.

5.7.4 External Events Impact Summary

In summary, the combination of the fire and seismic CDF values described above results in an external events risk estimates of 1.06E-05/yr (fire) and 2.65E-05/yr (seismic). These combined values are considered to be very bounding for this assessment. This compares to the Unit 1 internal events CDF of 3.16E-06/yr. Since the change in risk for the ILRT risk impact is a function of CDF, a multiplier will be used for the initial bounding assessment for the external events impact. Since individual seismic CDF class contributions are unknown, the seismic multiplier comparing total seismic CDF and FPIE CDF is applied.

Table 5.7-1 summarizes the estimated bounding external events CDF contribution for LGS.

TABLE 5.7-1

LGS EXTERNAL EVENTS CONTRIBUTOR SUMMARY

EXTERNAL EVENT INITIATOR GROUP	CDF (1/YR)	LERF (1/YR)
Seismic	2.65E-05	1.75E-06(1)
Internal Fire	1.06E-05	2.56E-07(2)
High Winds	Screened	Screened
Other Hazards	Screened	Screened
Total For External Events	**3.71E-05**	**2.01E-06**
Internal Events Values (for comparison)	3.16E-06	2.09E-07

Notes to Table 5.7-1:

(1) As noted in Section 5.7.2, seismic LERF is assumed to be the ratio of seismic CDF to FPIE CDF multiplied by FPIE LERF.

(2) The Unit 2 Fire PRA value is utilized since it is slightly higher than the Unit 1 value.

As noted earlier, the 3b contribution is approximately proportional to CDF. An increase in CDF would likely lead to higher 3b frequency and assumed LERF. To determine a suitable multiplier of external CDF to internal event CDF, a multiplier is developed for each external event group (i.e., fire and seismic) and then added together to address both contributors, as shown in Table 5.7-2.

TABLE 5.7-2

LGS EXTERNAL EVENTS TO INTERNAL EVENTS CDF COMPARISON

EXTERNAL EVENT INITIATOR GROUP	CDF (1/YR)	RATIO TO FPIE CDF
Seismic	2.65E-05	8.4
Internal Fire	1.06E-05	3.3
Total For External Events	**3.71E-05**	**11.7**
Internal Events CDF	3.16E-06	1.00

5.7.5 External Events Impact on ILRT Extension Assessment

The EPRI Category 3b frequency for the 3-per-10 year, 1-per-10 year, and 1-per-15 year ILRT intervals are shown in Table 5.6-1 as 7.51E-09/yr, 2.57E-08/yr, and 3.98E-08/yr, respectively. Using an external events multiplier of 11.7 for LGS, the change in the LERF risk measure due to extending the ILRT from 3-per-10 years to 1-per-15 years, including both internal and external hazards risk, is estimated as shown in Table 5.7-3.

TABLE 5.7-3

LGS 3B (LERF/YR) AS A FUNCTION OF ILRT FREQUENCY FOR INTERNAL AND EXTERNAL EVENTS (INCLUDING AGE ADJUSTED STEEL LINER CORROSION LIKELIHOOD)

	3B FREQUENCY (3-PER-10 YR ILRT)	3B FREQUENCY (1-PER-10 YEAR ILRT)	3B FREQUENCY (1-PER-15 YEAR ILRT)	LERF INCREASE[(1)]
Internal Events Contribution	7.51E-09	2.57E-08	3.98E-08	3.23E-08
External Events Contribution (Internal Events x 11.7)	8.82E-08	3.01E-07	4.68E-07	3.80E-07
Combined (Internal + External)	**9.57E-08**	**3.27E-07**	**5.08E-07**	**4.12E-07**

Note to Table 5.7-3:

(1) Associated with the change from the baseline 3-per-10 year frequency to the proposed 1-per-15 year frequency.

The other figures of merit can be similarly derived using the multiplier approach and compared to the acceptance criteria for the ILRT extension risk assessment. The results between the 3-in-10 year interval and the 15 year interval compared to the acceptance criteria are shown in Table 5.7-4. As can be seen, the impact from including the external events contributors would not change the conclusion of the risk assessment. That is, the acceptance criteria are all met such that the estimated risk increase associated with permanently extending the ILRT surveillance interval to 15 years has been demonstrated to be small. Note that a bounding analysis for the total LERF contribution follows Table 5.7-4 to demonstrate that the total LERF value for LGS is less than 1.0E-05/yr consistent with the requirements for a “Small Change” in risk of the RG 1.174 acceptance guidelines.

TABLE 5.7-4

COMPARISON TO ACCEPTANCE CRITERIA INCLUDING EXTERNAL EVENTS CONTRIBUTION FOR LGS

CONTRIBUTOR	ΔLERF	ΔPERSON-REM/YR	ΔCCFP
Internal Events	3.23E-08/yr	6.60E-02/yr (0.36%)	1.02%
External Events	3.80E-07/yr	7.75E-01/yr (0.36%)	1.02%
Total	**4.12E-07/yr**	**0.84yr (0.36%)**	**1.02%**
Acceptance Criteria	**<1.0E-6/yr**	**<1.0 person-rem/yr or <1.0%**	**<1.5%**

The 4.12E-07/yr increase in LERF due to the combined internal and external events from extending the ILRT frequency from 3-per-10 years to 1-per-15 years falls within Region II between 1.0E-7 to 1.0E-6 per reactor year ("Small Change" in risk) of the RG 1.174 acceptance guidelines. Per RG 1.174, when the calculated increase in LERF due to the proposed plant change is in the "Small Change" range, the risk assessment must also reasonably show that the total LERF is less than 1.0E-5/yr. Similar bounding assumptions regarding the external event contributions that were made above are used for the total LERF estimate.

From Table 4.2-3, the total LERF due to postulated internal event accidents is 2.09E-07/yr for LGS. As discussed in Section 5.7.2, the total LERF estimate for the Fire PRA model is 2.56E-07/yr. As discussed in Section 5.7.3, the total LERF estimate for the Seismic PRA model is 1.75E-06/yr. The total LERF values for LGS are shown in Table 5.7-5.

TABLE 5.7-5

IMPACT OF 15-YR ILRT EXTENSION ON LERF FOR LGS

LERF CONTRIBUTOR	(1/YR)
Internal Events LERF	2.09E-07
Fire LERF	2.56E-07
Seismic LERF	1.75E-06
Internal Events LERF due to ILRT (at 15 years) (1)	3.98E-08
External Events LERF due to ILRT (at 15 years) (1)	4.68E-07 [Internal Events LERF due to ILRT * 11.7]
Total	**2.72E-06/yr**

Note to Table 5.7-5:

(1) Including age adjusted steel liner corrosion likelihood as reported in Table 5.7-3.

As can be seen, the estimated upper bound LERF for LGS is estimated as 2.72E-06/yr. This value is less than the RG 1.174 requirement to demonstrate that the total LERF due to internal and external events is less than 1.0E-05/yr.

5.8 CONTAINMENT OVERPRESSURE IMPACTS ON CDF

As indicated in the EPRI ILRT report [3], in general, CDF is not significantly impacted by an extension of the ILRT interval. However, plants that rely on containment overpressure for net positive suction head (NPSH) for emergency core coolant system (ECCS) injection for certain accident sequences may experience an increase in CDF.

LGS does not credit containment overpressure for the mitigation of design basis accidents. The LGS ECCS pumps are designed to be able to pump saturated fluid. UFSAR [29] Section 6.3.2.2.4.1 utilizes saturated suppression pool temperature at atmospheric conditions to develop the available NPSH estimate which is above that required for both CS and LPCI. As such, the LGS PRA does not require containment pressurization above atmospheric conditions for successful ECCS injection. Therefore an increase in the containment leakage (e.g., EPRI Class 3b) that prevents containment overpressurization would have no affect on successful ECCS injection.

6.0 SENSITIVITIES

6.1 SENSITIVITY TO CORROSION IMPACT ASSUMPTIONS

The results in Tables 5.2-2, 5.3-1, and 5.3-2 show that including corrosion effects calculated using the assumptions described in Section 4.4 does not significantly affect the results of the ILRT extension risk assessment. In any event, sensitivity cases were developed to gain an understanding of the sensitivity of the results to the key parameters in the corrosion risk analysis. The time for the flaw likelihood to double was adjusted from every five years to every two and every ten years. The failure probabilities for the containment wall and basemat were increased and decreased by an order of magnitude. The total detection failure likelihood was adjusted from 10% to 15% and 5%. The results are presented in Table 6.1-1. In every case the impact from including the corrosion effects is very minimal. Even the upper bound estimates with very conservative assumptions for all of the key parameters yield increases in LERF due to corrosion of only 1.09E-7/yr. The results indicate that even with very conservative assumptions, the conclusions from the base analysis would not change.

TABLE 6.1-1

STEEL LINER CORROSION SENSITIVITY CASES FOR LGS

AGE (STEP 3 IN THE CORROSION ANALYSIS)	CONTAINMENT BREACH (STEP 4 IN THE CORROSION ANALYSIS)	VISUAL INSPECTION & NON-VISUAL FLAWS (STEP 5 IN THE CORROSION ANALYSIS)	INCREASE IN CLASS 3B FREQUENCY (LERF) FOR ILRT EXTENSION FROM 3 IN 10 TO 1 IN 15 YEARS (PER YEAR)	
			TOTAL INCREASE	INCREASE DUE TO CORROSION
Base Case Doubles every 5 yrs	Base Case (10% Wall, 1% Basemat)	Base Case (10% Wall, 100% Basemat)	3.23E-08	3.41E-09
Doubles every 2 yrs	Base	Base	3.67E-08	7.80E-09
Doubles every 10 yrs	Base	Base	3.18E-08	2.88E-09
Base	Base	15% Wall	3.37E-08	4.78E-09
Base	Base	5% Wall	3.10E-08	2.05E-09
Base	100% Wall, 10% Basemat	Base	6.31E-08	3.41E-08
Base	1.0% Wall, 0.1% Basemat	Base	2.93E-08	3.41E-10
LOWER BOUND				
Doubles every 10 yrs	1.0% Wall, 0.1% Basemat	5% Wall, 100% Basemat	2.91E-08	1.73E-10
UPPER BOUND				
Doubles every 2 yrs	100% Wall, 10% Basemat	15% Wall, 100% Basemat	1.38E-07	1.09E-07

6.2 EPRI EXPERT ELICITATION SENSITIVITY

An expert elicitation was performed to reduce excess conservatisms in the data associated with the probability of undetected leaks within containment [3]. Since the risk impact assessment of the extensions to the ILRT interval is sensitive to both the probability of the leakage as well as the magnitude, it was decided to perform the expert elicitation in a manner to solicit the probability of leakage as a function of leakage magnitude. In addition, the elicitation was performed for a range of failure modes which allowed experts to account for the range of failure mechanisms, the potential for undiscovered mechanisms, inaccessible areas of the containment as well as the potential for detection by alternate means. 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 basic difference in the application of the ILRT interval methodology using the expert elicitation is a change in the probability of pre-existing leakage within containment. The base case methodology uses the Jeffrey's non-informative prior for the large leak size and the expert elicitation sensitivity study uses the results from 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 base case methodology (i.e., 10La for small and 100La for large) are used here. Table 6.2-1 illustrates the magnitudes and probabilities of a pre-existing leak in containment associated with the base case and the expert elicitation statistical treatments. These values are used in the ILRT interval extension for the base methodology and in this sensitivity case. Details of the expert elicitation process, including the input to expert elicitation as well as the results of the expert elicitation, are available in the various appendices of EPRI 1018243 [3].

TABLE 6.2-1

EPRI EXPERT ELICITATION RESULTS

LEAKAGE SIZE (LA)	BASE CASE MEAN PROBABILITY OF OCCURRENCE	EXPERT ELICITATION MEAN PROBABILITY OF OCCURRENCE [3]	PERCENT REDUCTION
10	9.2E-03	3.88E-03	58%
100	2.3E-03	2.47E-04	89%

The summary of results using the expert elicitation values for probability of containment leakage (including corrosion) is provided in Table 6.2-2. As mentioned previously, probability values are those associated with the magnitude of the leakage used in the base case evaluation (10La for small and 100La for large). The expert elicitation process produces a relationship between probability and leakage magnitude in which it is possible to assess higher leakage magnitudes that are more reflective of large early releases; however, these evaluations are not performed in this particular study.

The net effect is that the reduction in the multipliers shown above also leads to a dramatic reduction on the calculated increases in the LERF values. As shown in Table 6.2-2, the increase in the overall value for LERF due to Class 3b sequences that is due to increasing the ILRT test interval from 3 to 15 years is just 3.11E-09/yr. Similarly, the increase due to increasing the interval from 10 to 15 years is just 1.30E-09/yr. As such, if the expert elicitation probabilities of occurrence are used instead of the non-informative prior estimates, the change in LERF is well within the range of a "very small" change in risk when compared to the current 1-in-10, or baseline 3-in-10 year requirement. Additionally, as shown in Table 6.2-2, the increase in dose rate and CCFP are similarly reduced to much smaller values. The results of this sensitivity study are judged to be more indicative of the actual risk associated with the ILRT extension than the results from the assessment as dictated by the values from the EPRI methodology [3], and yet are still conservative given the assumption that all of the Class 3b contribution is considered to be LERF.

TABLE 6.2-2
LGS ILRT CASES:
3 IN 10 (BASE CASE), 1 IN 10, AND 1 IN 15 YR INTERVALS
(BASED ON EPRI EXPERT ELICITATION LEAKAGE PROBABILITIES)

		BASE CASE 3 IN 10 YEARS		EXTEND TO 1 IN 10 YEARS		EXTEND TO 1 IN 15 YEARS	
EPRI CLASS	DOSE PER-REM	CDF (1/YR)	PERSON-REM/YR	CDF (1/YR)	PERSON-REM/YR	CDF (1/YR)	PERSON-REM/YR
1	1.56E+04	3.32E-07	5.17E-03	3.02E-07	4.70E-03	2.80E-07	4.36E-03
2	9.35E+06	9.78E-09	9.15E-02	9.78E-09	9.15E-02	9.78E-09	9.15E-02
3a	1.56E+05	1.22E-08	1.90E-03	4.06E-08	6.32E-03	6.10E-08	9.49E-03
3b	1.56E+06	7.76E-10	1.21E-03	2.59E-09	4.02E-03	3.88E-09	6.04E-03
7	6.50E+06	2.80E-06	1.818E+01	2.80E-06	1.818E+01	2.80E-06	1.818E+01
8	9.35E+06	6.94E-09	6.49E-02	6.94E-09	6.49E-02	6.94E-09	6.49E-02
Total		**3.16E-06**	**18.343**	**3.16E-06**	**18.350**	**3.16E-06**	**18.355**
ILRT Dose Rate from 3a and 3b		3.10E-03		1.03E-02		1.55E-02	
Delta Total Dose Rate(1)	From 3 yr	---		7.23E-03		1.16E-02	
	From 10 yr	---		---		4.85E-03	
3b Frequency (LERF)		7.76E-10		2.59E-09		3.88E-09	
Delta 3b LERF	From 3 yr	---		1.81E-09		3.11E-09	
	From 10 yr	---		---		1.30E-09	
CCFP %		89.10%		89.15%		89.19%	
Delta CCFP %	From 3 yr	---		0.06%		0.10%	
	From 10 yr	---		---		0.04%	

Note to Table 6.2-2:

(1) The overall difference in total dose rate is less than the difference of only the 3a and 3b categories between two testing intervals. This is due to the fact that the Class 1 person-rem/yr decreases when extending the ILRT frequency.

7.0 CONCLUSIONS

Based on the results from Section 5 and the sensitivity calculations presented in Section 6, and the DWBT analysis shown in Appendix B, the following conclusions regarding the assessment of the plant risk are associated with permanently extending the Type A ILRT and DWBT test frequency to fifteen years:

- Reg. Guide 1.174 [4] provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Reg. Guide 1.174 defines "very small" changes in risk as resulting in increases of CDF below 1.0E-06/yr and increases in LERF below 1.0E-07/yr. "Small" changes in risk are defined as increases in CDF below 1.0E-05/yr and increases in LERF below 1.0E-06/yr. Since the ILRT extension was demonstrated to have negligible impact on CDF for LGS, the relevant criterion is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval for the base case with corrosion included is 3.23E-08/yr (see Table 5.6-1). In using the EPRI Expert Elicitation methodology, the change is estimated as 3.11E-09/yr (see Table 6.2-2). Both of these values fall within the very small change region of the acceptance guidelines in Reg. Guide 1.174.
- The change in dose risk for changing the Type A test frequency from three-per-ten years to once-per-fifteen-years, measured as an increase to the total integrated dose risk for all internal events accident sequences for LGS, is 6.60E-02 person-rem/yr (0.36%) using the EPRI guidance with the base case corrosion included (Table 5.6-1). The change in dose risk drops to 1.16E-02 person-rem/yr (0.06%) when using the EPRI Expert Elicitation methodology (Table 6.2-2). The values calculated per the EPRI guidance are all lower than the acceptance criteria of ≤1.0 person-rem/yr or <1.0% person-rem/yr defined in Section 1.3.
- The increase in the conditional containment failure frequency from the three in ten year interval to one in fifteen years including corrosion effects using the EPRI guidance (see Section 5.5) is 1.02%. This value drops to 0.10% using the EPRI Expert Elicitation methodology (see Table 6.2-2). Both of these values are below the acceptance criteria of less than 1.5% defined in Section 1.3.
- To determine the potential impact from external events, a bounding assessment from the risk associated with external events was performed utilizing available information. As shown in Table 5.7-4, the total increase in LERF due to internal events and the bounding external events assessment is 4.12E-07/yr. This value is in Region II of the Reg. Guide 1.174 acceptance guidelines.

- As shown in Table 5.7-5, the same bounding analysis indicates that the total LERF from both internal and external risks is 2.72E-06/yr which is less than the Reg. Guide 1.174 limit of 1.0E-05/yr given that the ΔLERF is in Region II (small change in risk).
- Including age-adjusted steel liner corrosion effects in the ILRT assessment was demonstrated to be a small contributor to the impact of extending the ILRT interval for LGS.
- A DWBT risk analysis documented in Appendix B provides key metric values that, in combination with ILRT results, would not change the ILRT related conclusions described above. The DWBT values for an interval change from the original 3-in-10 years to 15 years are compared below to the ILRT base case with corrosion. These DWBT values are developed in Appendix B and reported in Appendix B, Section B.5.

Delta CDF	= 7.86E-10/yr	(ILRT increase = 0.0)
Delta LERF	= 3.60E-09/yr	(ILRT increase = 3.23E-08/yr)
Delta Dose	= 1.5E-02 p-rem/yr	(ILRT increase = 6.60E-02 p-rem/yr)
Delta CCFP	= 0.003%	(ILRT increase = 1.02%)

The DWBT CDF increase is less than 0.1% of Base CDF. The DWBT values for LERF and CCFP are significantly below the ILRT values. Although the DWBT person-rem dose rate increase is about one-fourth of the ILRT dose rate increase, the total dose rate increase is still less than 0.5% which is well less than the acceptance criteria of less than 1.0% increase.

Therefore, increasing the ILRT and DWBT intervals on a permanent basis to a one-in-fifteen year frequency is not considered to be significant since it represents only a small change in the LGS risk profiles.

Previous Assessments

The NRC in NUREG-1493 [6] has previously concluded the following:

- Reducing the frequency of Type A tests (ILRTs) from three per 10 years to one per 20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk is small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Type B and C testing, and the leaks that have been found by Type A tests have been only marginally above existing requirements.
- Given the insensitivity of risk to containment leakage rate and the small fraction of leakage paths detected solely by Type A testing, increasing the interval between integrated leakage-rate tests is possible with minimal impact on public risk. The impact of relaxing the ILRT frequency beyond

one in 20 years has not been evaluated. Beyond testing the performance of containment penetrations, ILRTs also test the integrity of the containment structure.

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

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APPENDIX A
PRA TECHNICAL ADEQUACY

A PRA TECHNICAL ADEQUACY

A.1 OVERVIEW

A technical Probabilistic Risk Assessment (PRA) analysis is presented in this report to help support an extension of the LGS Unit 1 and Unit 2 containment Type A Integrated Leak Rate Test (ILRT) and Drywell Bypass Test (DWBT) interval to fifteen years.

The analysis follows the guidance provided in Regulatory Guide 1.200, Revision 2 [A.1], "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities." The guidance in RG-1.200 indicates that the following steps should be followed to perform this study:

1. Identify the parts of the PRA used to support the application
   a. SSCs, operational characteristics affected by the application and how these are implemented in the PRA model.
   b. A definition of the acceptance criteria used for the application.
2. Identify the scope of risk contributors addressed by the PRA model
   a. If not full scope (i.e. internal and external), identify appropriate compensatory measures or provide bounding arguments to address the risk contributors not addressed by the model.
3. Summarize the risk assessment methodology used to assess the risk of the application
   a. Include how the PRA model was modified to appropriately model the risk impact of the change request.
4. Demonstrate the Technical Adequacy of the PRA
   a. Identify plant changes (design or operational practices) that have been incorporated at the site, but are not yet in the PRA model and justify why the change does not impact the PRA results used to support the application.
   b. Document peer review findings and observations that are applicable to the parts of the PRA required for the application, and for those that have not yet been addressed justify why the significant contributors would not be impacted.
   c. Document that the parts of the PRA used in the decision are consistent with applicable standards endorsed by the Regulatory Guide. Provide justification to show that where specific requirements in the standard are not met, it will not unduly impact the results.

d. Identify key assumptions and approximations relevant to the results used in the decision-making process.

Items 1 through 3 are covered in the main body of this report. The purpose of this appendix is to address the requirements identified in item 4 above. Each of these items (plant changes not yet incorporated into the PRA model, relevant peer review findings, consistency with applicable PRA standards and the identification of key assumptions) are discussed in the following sections.

The risk assessment performed for the ILRT extension request is based on the current Level 1 and Level 2 PRA model. Note that for this application, the accepted methodology involves a bounding approach to estimate the change in the LERF from extending the ILRT/DWBT interval. Rather than exercising the PRA model itself, it involves the establishment of separate evaluations that are linearly related to the plant CDF contribution. Consequently, a reasonable representation of the plant CDF that does not result in a LERF does not require that Capability Category II be met in every aspect of the modeling if the Category I treatment is conservative or otherwise does not significantly impact the results.

A discussion of the Exelon model update process, the peer reviews performed on the LGS models, the results of those peer reviews and the potential impact of peer review findings on the ILRT/DWBT extension risk assessment are provided in Section A.2. Section A.3 provides an assessment of key assumptions and approximations used in this risk evaluation. Finally, Section A.4 briefly summarizes the results of the PRA technical adequacy assessment with respect to this application.

A.2 PRA MODEL EVOLUTION AND PEER REVIEW SUMMARY

A.2.1 Introduction

The 2017 versions of the LGS PRA models are the most recent evaluations of the Unit 1 and Unit 2 risk profile at LGS for internal event challenges. The LGS 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 LGS PRA is based on the event tree / fault tree methodology, which is a well-known methodology in the industry.

Exelon Generation Company, LLC (Exelon) employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA models for all operating Exelon 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 this approach as it applies to the LGS PRA.

<u>PRA Maintenance and Update</u>

The Exelon risk management process ensures that the applicable PRA model is an accurate reflection of the as-built and as-operated plants. This process is defined in the Exelon Risk Management program, which consists of a governing procedure and subordinate implementation procedures. The PRA model update procedure delineates the responsibilities and guidelines for updating the full power internal events PRA models at all operating Exelon nuclear generation sites. The overall Exelon Risk Management program defines the process for implementing regularly scheduled and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, industry operating experience, etc.), and for controlling the model and associated computer files. To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plants, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model.
- Maintenance unavailabilities are captured, and their impact on CDF is trended.
- Plant specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated approximately every four years.

In addition to these activities, Exelon risk management procedures provide the guidance for particular risk management maintenance activities. This guidance includes:

- Documentation of the PRA model, PRA products, and bases documents.
- The approach for controlling electronic storage of Risk Management (RM) products including PRA update information, PRA models, and PRA applications.
- Guidelines for updating the full power, internal events PRA models for Exelon Nuclear Generation sites.
- Guidance for use of quantitative and qualitative risk models in support of the On-Line Work Control Process Program for risk evaluations for maintenance tasks (corrective maintenance, preventive maintenance, minor maintenance, surveillance tests and modifications) on systems, structures, and components (SSCs) within the scope of the Maintenance Rule (10 CFR 50.65(a)(4)).

In accordance with this guidance, regularly scheduled PRA model updates nominally occur on an approximately 4-year cycle; longer intervals may be justified if it can be shown that the PRA continues to adequately represent the as-built, as-operated plant. The 2017 models were completed in July of 2018.

As indicated previously, RG 1.200 also requires that additional information be provided as part of the LAR submittal to demonstrate the technical adequacy of the PRA model used for the risk assessment. Each of these items (plant changes not yet incorporated into the PRA model, relevant peer review findings, and consistency with applicable PRA Standards) will be discussed in turn in this section.

A.2.2 Plant Changes Not Yet Incorporated into the PRA Model

A PRA updating requirements evaluation (URE- Exelon PRA model update tracking database) is created for all issues that are identified that could impact the PRA model. The URE database includes the identification of those plant changes that could impact the PRA model.

A review of the open UREs indicates that there are no plant changes that have not yet been incorporated into the PRA model that would affect this application.

A.2.3 Consistency with Applicable PRA Standards

Several assessments of technical capability have been made for the LGS internal events PRA models. These assessments are as follows and further discussed in the paragraphs below.

The LGS PRA model for internal events received a formal industry peer review in November 1998. The model was updated in 2001 to address the significant findings from that review. Following that update, LGS was one of five nuclear plants that piloted application of RG 1.200 so a site PRA gap analysis which compared the LGS PRA to the requirements of the NRC-endorsed ASME PRA Standard was completed in 2003 in support of the LGS pilot for Risk-Informed activities. Additionally, the LGS PRA model was subject to an NRC RG 1.200 pilot assessment in July 2004, and following the completion of the PRA model update in 2005 to strategically address the identified gaps, a peer review against draft Addendum B of the ASME PRA Standard [A.2] was performed in October, 2005.

The Full Power Internal Events (FPIE) peer review performed in 2005 found that 97% of the SR's evaluated Met Capability Category II or better. There were seven SRs that were assessed as "Not Met" and two SRs that were assessed as meeting Capability Category 1. As noted in the peer review report, the majority of the findings were documentation related. Of the nine SRs which were assessed as not meeting Capability Category II or better, all were related to documentation issues in which two were also related to minor modeling enhancements that improve quantification. Additionally, one Finding was self-identified involving test and maintenance pre-initiators for a number of significant systems, but these were not derived from a formal review of procedures and practices.

In May of 2008, a focused peer review against Addendum B of the ASME PRA Standard of the updated Internal Flooding (IF) analysis was performed. The IF peer review encompassed a review of the internal flood at-power PRA, consistent with the scope of the ASME PRA Standard RA-Sb-2005 [A.3] as endorsed and clarified at the time by the

NRC in RG 1.200, Revision 1 [A.4]. Of the 50 SRs evaluated, there were eight that were assessed as "Not Met" and 3 SRs which did not meet Capability Category II or better. These 11 SRs that were either "Not Met" or Capability Category I were mostly related to minor model enhancements and documentation issues.

The 2005 FPIE peer review findings and the 2008 internal flood peer review findings were addressed in the LGS PRA, and in July, 2016 a review of the peer review findings and the resolutions was performed by an independent review team [A.5]. The independent review team concluded that, for the FPIE, three findings were not resolved (and one open item was not reviewed). Two of the four findings are documentation related, and one of the findings can be addressed by a minor model change. For the Internal Flood (IF) findings, the review team concluded that two findings were resolved, one finding was not resolved and that eight findings were partially resolved. The nine unresolved IF findings are mostly related to minor model enhancements and documentation issues.

Additionally, a gap assessment to the current standard, ASME/ANS Ra-Sa-2009 [A.6], and RG 1.200, Revision 2 [A.1] has been performed. The gap assessment did not identify any deficiencies that were not identified by the peer reviews or were not previously self-identified with respect to the new standard, and the remaining open items are consistent with the 2016 independent review team conclusions.

A.2.4 Applicability of Peer Review Findings and Observations

The remaining set of open or partially resolved findings from the independent review team assessment are described in Table A-1 for internal events and internal flooding with their impact on this application noted. The current status reflects what has been done following completion of the 2017 model update where most of the remaining findings have been addressed.

TABLE A-1

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPIE AND IF FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	PRIOR STATUS / CURRENT STATUS	IMPORTANCE TO APPLICATION
SY-A11-03	High pressure makeup is credited for 4 hours without AC available. Per the DC system notebook, the battery life for each division is 2 hours. The model credits running HPCI and RCIC for two hours and when one system is operating the other is secured. However, the procedures that direct this operation are only entered during a SBO. These two systems are vulnerable to DC depletion for scenarios where at least one diesel generator is not failed but the battery chargers for the HPCI and RCIC batteries do not have AC available.	SY-A11 (Now SY-A10)	Important and necessary to address, but may be deferred until the next PSA update. Considered necessary to meet Capability Category II.	Open: The Event Tree Notebook Section 9 contains the event tree for this scenario. Node U1' is the top event that addresses the extension of operating time from two hours to at least four hours in a serial fashion. A separate sensitivity study which always required the chargers to be available to get out to four hours indicated that there is a negligible impact on the results (i.e., << 1% increase in CDF). Current Status: The serial operation of HPCI and RCIC in the LOOP event tree has been removed from the model used for this application.	No impact.
HR-A1-01 (Self-identified)	The supporting requirement indicates that the test and maintenance pre-initiators should be derived from a review of procedures and practices.	HR-A1	The model includes several test and maintenance pre-initiators for a number of risk significant systems, but these were not derived from a formal review of procedures and practices.	Open – Not assessed by independent review team: Current Status: The test and maintenance pre-initiators have been identified and updated in the model used for this application.	No impact.

TABLE A-1

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPIE AND IF FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	PRIOR STATUS / CURRENT STATUS	IMPORTANCE TO APPLICATION
QU-F5-01	Provide a discussion for the limitations of the quantification process that could impact applications (e.g., online maintenance, MPSI). One of the topics could be the WinNUPRA code limitations on the maximum number of cutsets and its impact on quantification truncation limits.	QU-F5	Marginal importance, but considered desirable to maintain maximum flexibility in PSA Applications and consistency in the Industry.	Open: The LGS Fire PRA summary and quantification notebook discusses the quantification process limitations on applications. However, a similar discussion applicable to the FPIE model documentation is not included for the internal events. WinNUPRA is no longer used in the Limerick PRA and truncation is not applied at a sequence level. Note that the conversion to CAFTA from WinNUPRA did not constitute an upgrade due to the extensive benchmarking of results that was performed as part of the conversion documentation. (Example 11 of the Non Mandatory Appendix 1-A of the ASME / ANS RA-Sa-2009 states that the conversion of one fault tree linking code to another is PRA maintenance.) Current Status: An appendix has been added to the FPIE Summary Notebook to discuss the CAFTA software limitations in the model used for this application.	No impact.

TABLE A-1

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPIE AND IF FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	PRIOR STATUS / CURRENT STATUS	IMPORTANCE TO APPLICATION
QU-F6-01	Other than for HRA, the LGS documentation does not include the applied definition of "significant". Based on the review, the definitions provided in the ASME PRA Standard appear to have been generally applied.	QU-F6	Marginal importance, but considered desirable to maintain maximum flexibility in PSA Applications and consistency in the Industry.	Open: The definitions in the PRA Standard are applied, but other than for HRA and the definition of a significant sequence in the FPIE model, the LGS documentation does not include the applied definition of "significant". There is no definition of a significant basic event or a significant cutset, and while the definition of significant sequence is used it is not actually defined. Current Status: An appendix has been added to the FPIE Summary Notebook defining significant sequences, basic events, and cutsets in the model used for this application.	No impact.
IF-B3-01	Analysis of the TECW, RECW, CECW, and DWCW only considers the volume of water in the surge tank, not total system volume. Any system breach would result in gravity draining the system until level reaches that of the break. The TECW and RECW could contain significant volumes such that the scenarios may not be screened. Similarly, a break in the chilled water systems could release more water than in the surge tank. The DECW and RECW systems have automatic makeup to the surge tanks which could add water to the flood source.	IF-B3 (Now IFSO-A5)	Since flood areas are documented as screened based on limited system volume, additional scenarios may need to be considered in the PRA if the system volume is considered.	Partially Resolved: The documentation does not clearly identify the reasons for screening. Instead, the internal flood notebook provides a summary of screening. Flood scenarios were screened based on hazard which includes a combination of flood source volume and if equipment in the area can be failed by the flood. These details are not included in the notebook. Current Status: The Internal Flooding Notebook has been updated to discuss the flood sources in the model used for this application.	No impact.

TABLE A-1

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPIE AND IF FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	PRIOR STATUS / CURRENT STATUS	IMPORTANCE TO APPLICATION
IF-C2a-01	No automatic actions were identified as being credited for flood termination or mitigation. Operator actions that are credited with terminating or mitigating a flooding event are generally described in Appendix E. However, the specific actions, such as, "close valve, V-XX," are not described in detail. The analyses shown in Appendix E reference the HRA performed in Appendix F.	IF-C2a (Now IFSN-A3)	It appears from a review of appendices E and F that major actions needed have been identified.	Partially Resolved: The internal flood notebook documents the operator actions credited for internal flood initiators. The documentation provides detailed plant response, cues, location, timing, and execution information for each credited action. The documentation references the HRA notebook which provides the HEP calculation worksheets and further details regarding HFEs FHUC31DXI, FHUC32DXI, and FHUC33DXI, and also documents that a screening value of 0.1 was assigned for HFEs FHURB9DXI and FHUCE1DXI. However, there are some discrepancies in the documentation of the operator actions which need to be fixed. Current Status: The Internal Flooding Notebook has been updated to reflect the correct HEPs from the HRA Notebook.	No impact.

TABLE A-1

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPIE AND IF FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	PRIOR STATUS / CURRENT STATUS	IMPORTANCE TO APPLICATION
IF-C2b-01	Appendix E appears to take credit for drains, however calculation of drain capacity was not evident.	IF-C2b (Now IFSN-A4)	No specific analysis of drains appears to have been performed.	Open: A formal analysis of drain capacities has not been performed. The internal flood notebook provides a discussion of flood scenarios in Flood Zone RB-FL09. A drain capacity of 60,000 gallons was estimated and credited based on discussion with engineers and review of plant drawings. A probabilistic estimate of drainage failure is provided to address uncertainties in the drainage capacity. With the exception of Flood Zone RB-FL09, floor drains were not credited to conservatively estimate the time available for operator intervention. Current Status: The Internal Flooding Notebook has been updated to discuss the flood scenarios that includes evaluation of drains in the model used for this application.	No impact.

TABLE A-1

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPIE AND IF FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	PRIOR STATUS / CURRENT STATUS	IMPORTANCE TO APPLICATION
IF-C3b-01 IF-C3b-03	IF-C3b-01: No consideration of barrier unavailability due to maintenance and how such unavailability could affect flood scenarios was documented. IF-C3b-03: LG-PRA-012, section 3.3.2.1, page 3-10, first paragraph describes how the EDG rooms are independent by discussing on doors and the corridor. Drains and electrical penetrations that may exist between the EDG rooms. Also, drains between the CE, TE, and RE are not discussed.	IF-C3b (Now IFSN-A8)	IF-C3b-01: Evaluation of barrier unavailability could result insignificantly different flood scenarios. Evaluation of barrier unavailability is required by RG 1.200. IF-C3b-03: IF-C3b requires to IDENTIFY inter-area propagation through the normal flow path from one area to another via drainlines; and areas connected via back flow areas connected via back flow through drain lines involving through drain lines involving failed check valves, pipe and failed check valves, pipe and cable penetrations...etc".	Partially Resolved: Section 3.4.10 of internal flooding notebook documents impacts of barrier unavailability. Section 3.4.12 documents considerations of backflow in drains where credited. Section 3.4.13 documents considerations of inter-area propagation flow paths. Section 3.4.14 documents considerations of structural analysis of doors where credited. Section 2.2.11 documents considerations of backflow through drains. The analysis does not explicitly address water entering flood zones via backflow through the drain piping since there are check valves installed in the drains that service the ECCS rooms in the basement of the Reactor Enclosure that prevent propagation of water from one room to another. Also, most internal drain lines within the plant drain to the Radioactive Waste system, which was observed to have a storage capacity of over 60,000 gallons Thus, backflow through drain lines was not explicitly modeled. Current Status: The check valve scenarios have been dispositioned as negligible risk contributors.	Check valve failures have small failure probabilities. Inclusion of scenarios with these failures will have negligible risk impact. There is no material impact on this application.

TABLE A-1

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPIE AND IF FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	PRIOR STATUS / CURRENT STATUS	IMPORTANCE TO APPLICATION
IF-D1-01	All flooding initiators are classified as either turbine trip or manual shutdown events as documented in Appendix D. The LGS model includes loss of service water. TECW, RECW, and AC switchgear as special initiating events. As shown in Appendix C, several service water breaks are included in the internal flooding analysis, yet it is not clear why the events, were developed as turbine trip events as opposed to loss of service water events. As discussed under SR IF-B3, flooding events involving TECW and RECW were screened based on limited system volume. When flooding involving TECW and RECW are reevaluated, this SR must be considered. The documentation does not describe why flooding events that cause a loss of switchgear are not evaluated as a loss of AC switchgear.	IF-D1 (Now IFEV-A1)	It appears that some internal flooding scenarios may have been associated with an inappropriate initiating event.	Partially Resolved: Consistent with the SR IFEV-A1, an evaluation of the flood sources and subsequent scenarios was performed to group the initiating events. The events are generally classified as initiators that include either a turbine trip or manual shutdown event, as appropriate, with the impact of the initiator implied to fail those SSCs that are influenced by both internal flooding and spray effects. Where necessary, sub-scenario frequencies were identified for specific components that were susceptible to nearby spray sources. That is, certain SSCs were considered vulnerable to only those nearby sources of water that could render that particular component unavailable, i.e., approximately 10 feet within a given spray source. However, the internal flood notebook does not document the specific mapping of flood scenarios to support system initiating events. Current Status: The internal flooding notebook used for this application has been updated to include a table that identifies each modeled flooding initator and its corresponding internal events initator to which it is mapped.	No impact

TABLE A-1

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPIE AND IF FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	PRIOR STATUS / CURRENT STATUS	IMPORTANCE TO APPLICATION
IF-E1-01	All flooding initiators are classified as either turbine trip or manual shutdown events as documented in Appendix D. The LGS model includes loss of service water. TECW, RECW, and AC switchgear as special initiating events. As shown in Appendix C, several service water breaks are included in the internal flooding analysis, yet it is not clear why the events, were developed as turbine trip events as opposed to loss of service water events. Had flooding sequences been reviewed for applicability, the appropriate accident sequence could have been associated with the proper internal initiating events group. No documentation of a sequence review was performed.	IF-E1 (Now IFQU-A1)	Since flooding events appear to be improperly categorized and no documentation of a sequence review for applicability was found, this is assigned as a Finding.	Partially Resolved: Consistent with the SR IFEV-A1, an evaluation of the flood sources and subsequent scenarios was performed to group the initiating events. The events are generally classified as initiators that include either a turbine trip or manual shutdown event, as appropriate, with the impact of the initiator implied to fail those SSCs that are influenced by both internal flooding and spray effects. Where necessary, sub-scenario frequencies were identified for specific components that were susceptible to nearby spray sources. That is, certain SSCs were considered vulnerable to only those nearby sources of water that could render that particular component unavailable, i.e., approximately 10 feet within a given spray source. However, the internal flood notebook does not document the specific mapping of flood scenarios to support system initiating events is not included. Current Status: The internal flooding notebook used for this application has been updated to include a table that identifies each modeled flooding initator and its corresponding internal events initator to which it is mapped.	No impact.

TABLE A-1

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPIE AND IF FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	PRIOR STATUS / CURRENT STATUS	IMPORTANCE TO APPLICATION
IF-E5a-01	No systematic assessment of the existing operator actions that are included in flood sequences was performed.	IF-E5a (Now IFQU-A6)	An assessment of existing HFEs is required by the standard.	Partially Resolved: Appendix G of the HRA notebook documents that all Internal Events HEPs were reviewed for internal flood. Most of the HEPs screened, and only those ex-CR actions that would occur earlier than 4 hours were examined in more detail. The HRA dependency analysis included the individual flood response HEPs as part of the development of the any joint human error probabilities. However, enhancements to the documentation were identified to include the basis for the initial screening process and include a summary table of all post-initiator HFEs and how each is addressed for flood. Current Status: The operator actions were assessed due to flooding scenarios and actions that were considered failed as a results of specific flooding scenarios were incorporated into the model.	No impact.

TABLE A-1

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPIE AND IF FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	PRIOR STATUS / CURRENT STATUS	IMPORTANCE TO APPLICATION
IF-E7-01	No review or quantification of flood-related LERF sequences is performed or documented.	IF-E7 (Now IFQU-A10)	This requirement requires that quantification be performed in accordance with section 4.5.8. That paragraph requires that LERF be quantified.	Partially Resolved: Section 4.2, Figure 4.2, and Figure 4.4 of the internal flood notebook provide results of flood-related LERF. Flood scenarios or initiators that contribute to LERF are provided. Figure ES-2A and Figure ES-2B of the summary notebook provide flood-related contributions to total LERF. Section 6.0, Appendix G, Appendix H, and Appendix I of quantification notebook provides the LERF quantification results (including internal flood). Flood-related cutsets are provided. Sequence contributions to flood-related LERF were quantified including potential containment failure mode contributions (e.g., containment isolation, containment bypass, etc.) to flood-related LERF. A documentation enhancement was identified to include sequence and damage class contributions to flood-related LERF. Current Status: The summary notebook includes LERF accident class contributions due to flooding scenarios, but the sequence results are not broken down specifically for flooding initiators.	This is a documentation issue with no impact on this application.

A.2.5 External Events

Although EPRI report 1018243 [A.8] recommends a quantitative assessment of the contribution of external events (for example, fire and seismic) where a model of sufficient quality exists, it also recognizes that the external events assessment can be taken from existing, previously submitted and approved analyses or another alternate method of assessing an order of magnitude estimate for contribution of the external event to the impact of the changed interval. Based on this, currently available information for external events models was referenced, and a multiplier was applied to the internal events results based on the available external events information. This is further discussed in Section 5.7 of the risk assessment.

A discussion of the unscreened external events contributors (i.e., internal fire hazards and seismic hazards) follows.

Internal Fire Hazards

The LGS Fire PRA (FPRA) peer review was performed November 2011 using the NEI 07-12 Fire PRA peer review process [A.7], the ASME PRA Standard, ASME/ANS RA-Sa-2009 [A.6] and Regulatory Guide 1.200, Rev. 2 [A.1]. The purpose of this review was to establish the technical adequacy of the FPRA for the spectrum of potential risk-informed plant licensing applications for which the FPRA may be used. The 2011 LGS FPRA peer review was a full-scope review of all of the technical elements of the LGS at-power FPRA against all technical elements in Part 4 of the ASME/ANS PRA Standard, including the referenced internal events supporting requirements (SRs). The peer review noted a number of facts and observations (F&Os). The findings were addressed in the LGS FPRA and in July, 2016 a review of the FPRA peer review findings and the resolutions was performed by an independent review team [A.5]. The independent review team concluded that 14 of the findings were either partially resolved or still open. An additional five findings were not assessed by the independent review team since they were assessed as being open prior to the independent review.

The remaining set of open or partially resolved findings from the independent review team assessment are described in Table A-2 for the internal fire hazard group and their impact on this application noted.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
1-4	Review of dependencies (power supply, interlock circuits and instrumentation) was not performed for components whose failure would cause an initiating event. During the peer review, three of four examples of dependency modeling were reviewed with Limerick PRA team and it was concluded that their dependencies are correctly considered. However, in other case of example, LTP94BHWI, evidence of dependency modeling was not provided to review team. It is believed that the pressure transmitter (PT-42-1N094B) needs to be supported by electrical system to perform its function, but the dependency is not included to the fire PRA logic. Furthermore, the BE's parent event (GHPC2A5) was ANDed with Div. IV gate and no power dependency is modeled under this event also. The other example was annunciation (KAN24AHWI). Generally, annunciations are supported by AC/DC power. However, review team couldn't identify any logic of power dependency of annunciations. Based on the above condition it was concluded that no systematic review of dependency was performed in Limerick fire PRA.	ES-A2	Unclear documentation on the need for power cables for new components included in Table F-1 of the model development notebook.	Open: A systematic review was performed using the internal events model, the safe shutdown analysis, and MSO evaluations. However FPRA notebooks do not provide documentation that identifies dependencies and how the dependency is modeled. The modeling of the power supply for LTP94BHWI is for HPCI Auto Initiation. Div. II DC is required for successful Auto HPCI Initiation. Therefore, the modeling of the Div. II DC power dependency is consistent with HPCI operation. This modeling approach is similar for CS. That is, the applicable division DC is required for pump operation, as well as, the Auto CS Initiation logic. Therefore, modeling the DC power dependency higher in the logic fails the pump AND auto and manual initiation. This is consistent with CS operation.	This is a documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
1-4 (Cont'd)		ES-A2		The example of the annunciator (KAN24AHWI) is not modeled for fire induced failure consistent with the HRA assumptions using screening HEPs and not modeling instrumentation for non-significant actions. The annunciator event is modeled for action KHULMIDXI-F which has an F-V of ~1E-6 and a RAW of 1.	

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
1-16	Limerick fire PRA was used truncation values of 1E-11 and 1E-12 for CDF and LERF, respectively without checking of convergence. In case of CDF calculation, 1E-8 was applied for truncation value for CCDP and final cutsets are truncated by 1E-11 after multiplying scenario frequency. This is applicable only when every scenario frequencies are less than 1E-3. However, there are some fire scenarios that scenario frequency is more than 1E3. Therefore, incorrect truncation approach is applied to limerick fire PRA. LERF case is same as CDF. Convergence check was performed with only one merged cutset file generated using single cutoff value of 1E-8 in the Limerick fire PRA. SR, QU-B3 is designed to check that the overall model results converge and that no significant accident sequences are inadvertently eliminated. To meet the SR, QU-B3, it is necessary to generate other merged cutest files by using different cutoff values and compare them to see if model converges.	FQ-F1	Convergence test appears incorrect. CCDP truncation may result in lost cutsets for higher frequency scenarios.	Partially Resolved: The FPRA summary and quantification notebook, Section 4.1, Table 4-3 and Table 4-4 document the truncation sensitivity analysis performed for CDF and LERF. A CCDP convergence approach is not being used; convergence is based on CDF. Therefore, this aspect of the Finding is resolved. The FPRA models of record use a CDF and LERF truncation of 1E-11/yr and 1E-12/yr, respectively. At these truncations levels a check for convergence resulted in more than a 5% change in CDF and LERF. These truncation limits are more than four orders of magnitude less than the calculated CDF and LERF. The check for convergence did not result in the identification of new risk significant events.	To be resolved in the next LGS FPRA update. The impact on the FPRA results is minimal, and therefore there is no material impac ton this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
2-8	Realistic success criteria and timing was not evaluated and documented for MSIV spurious operation. ASM-03 notebook Section 3.1.1.9 states below: The combination of the MSIVs spuriously opening was previously included in the ASM-01 model as a break outside containment initiating event. However, during review of the Fire PRA model, it was determined that this logic would be more accurate as leading to a LLOCA. However, the technical bases supporting this conclusion is lacking (e.g., MAAP runs supporting the conclusion).	PRM-B6	Lack of technical bases. Most probably documentation issue based on discussion with site risk management team. However, MSIV scenarios are significant to the FPRA.	Open - Not assessed by independent review team: The treatment of spurious MSIV opening scenarios currently leads to appropriate success criteria for injection requirements, and a conservative treatment of containment heat removal requirements associated with those scenarios. The finding indicated that the characterization of a MSIV spurious opening as a LLOCA above TAF was not supported by T/H evaluations. This discussion is not currently included in the FPRA documentation. The finding is related to the documentation of the justification that spurious MSIV closure success criteria is adequate.	This is a documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
2-20	The FPRA documentation is not complete for the system functions and boundary, the associated success criteria, the modeled components and failure modes including human actions, and a description of modeled dependencies including support system and common cause failures, including the inputs, methods, and results. Many model changes refer back to the UREs listed in Table 2-1 of ASM-03 notebook. However, the UREs do not have the pedigree of FPIE system models and they do not meet the requirements of SR SY-C2.	PRM-C1 (SY-C2)	Document the updated and added new system models in FPRA in accordance with applicable SR SY-C2 requirements.	Open - Not assessed by independent review team: The changes to the system models were made using the same methodologies that were utilized for the development of the FPIE models. The changes were documented in separate analysis files or the model change database for traceability and independently reviewed. The formal documentation associated with these model changes will be captured as part of the normal PRA update process.	This is a documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
2-25	LG-PRA-021.05 Section 10. Generic estimates per NUREG/CR-6850 are used, the system is operational during plant operation, and no outlier behavior has been identified. However, there is no documentation to verify that: a) the credited fire detection and suppression system is installed and maintained in accordance with applicable codes and standards, and b) the credited system is in a fully operable state during plant operation. Note that walkdown may be required to confirm that fire detection and suppression systems are available in the PAUs crediting such systems. Also, scope of risk relevant fire suppression and detection systems not identified.	FSS-D7	Identify risk relevant suppression and detection systems. Review and document plant fire detection and suppression systems to confirm that a) the credited fire detection and suppression system is installed and maintained in accordance with applicable codes and standards, and b) the credited system is in a fully operable state during plant operation.	Open: Section 3.8 of the fire modeling treatments notebook documents that the fire protection detection and suppression system impairments were reviewed in 2015. The review determined that the unavailability of the systems is low compared to the generic unreliability value used. However, no documentation of the details of the review are included in the FPRA notebooks.	This is a documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
2-26	Several fire scenarios credited the fire detection and suppression systems. However, the effectiveness in the context of each fire scenario is not analyzed and documented. Fire detection or suppression system effectiveness depends on, at a minimum, the following: 1) system design complies with applicable codes and standards, and current fire protection engineering practice, 2) the time available to suppress the fire prior to target damage, 3) specific features of physical analysis unit and fire scenario under analysis (e.g., pocketing effects, blockages that might impact plume behaviors or the "visibility" of the fire to detection and suppression systems, and suppression system coverage), and 4) suitability of the installed system given the nature of the fire source being analyzed. The above required documentation is not evident.	FSS-D8	Assess and document the fire detection and suppression systems effectiveness in the context of each fire scenario analyzed.	Open: The FPRA documentation does not include details of the assessment. The fire modeling treatments notebook, documents the credited systems were assessed to be effective based on plant walkdowns and review of the fire protection program. Table 3-1 lists the systems credited and provides comments for the credited given. Entries without a specific comment are only credited in the multi-compartment analysis. That is, the credit given is only to prevent a fire progressing to an adjacent room. These systems are not credited to prevent damage in the room where the fire originates. The fire protection health report performance indicators worksheets for multiple years were reviewed to ensure the systems are in compliance with applicable codes and standards.	This is a documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
2-31	The fire scenario notebook section 13.3 states that the risk significant basic events were identified for detailed circuit failure evaluation. A check of top scenarios, however, shows that numerous hot short failure probabilities were not set to the generic values. Based on communication with LGS risk management team, the majority of these hot short failure probabilities did not need to be incorporated into the reviewed top scenarios because either the scenario does not need to (e.g., 025_B), or the equipment has already failed with other cable failures (e.g., 013_F0E1-2). The review confirmed that LGS has performed sufficient circuit failure analysis for top risk contributors. However, the included equipment list in Table 13-2 of the FSS notebook is relatively short, which shows that not all risk significant contributors have been included. Identification of the specific components would require a detailed 'ones' run with post-processing, which was not performed for the peer review due to timing. It should be noted that the benefits to include more circuit failure analysis would be much less comparing with the listed components. On the other hand, some cables were mapped to all failure modes. For example, 1AA11509B is tied to breaker FTO, FTC and FTRC failure modes. Detailed circuit analysis should limit the failure for a particular fire scenario.	CF-A1	Perform more detailed circuit failure and likelihood evaluations for risk significant contributors.	Open: The risk significant contributors were reviewed to ensure appropriate generic values were applied for the fire scenarios. The generic aggregate probability is the default value applied. The review identified that because no off scheme cables are damaged in the applicable scenarios that the value is appropriate value. The review is not in the FPRA documentation. For example spurious events ECB0602HOI-AGG and ECB609HOI-AGG are risk significant and applicable to the most significant fire scenario. For this fire scenario the off scheme cables are not damaged in the fire scenario. Therefore, use of the aggregate probability of 0.4 is appropriate.	This is a documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
3-4	The Seismic Fire Interaction and the 1995 IPEEE address the potential for spurious operation or rupture of fire suppression systems however spurious operation of detection systems is not addressed. In addition the potential for loss of habitability due to gaseous system discharge or loss of availability due to diversion of suppressants from areas where they might be needed is not addressed. Therefore the assessment performed in the 1995 IPEEE and accordingly the Seismic Fire Interaction Analysis does not address all of the aspects required by the standard. Accordingly this SR is considered not met.	SF-A2	Perform an assessment of the potential seismic effects on fire suppression and detection systems with regard to spurious operation, system rupture, suppressant diversion, and PAU loss of habitability.	Partially Resolved: Section 3 and 4 of the seismic fire interactions notebook, Sections 3.1.2 and 4.1.2 discuss spurious operation of fire systems. These sections reference the new walkdowns that were performed as part of the LGS seismic PRA which are documented in the Seismic PRA walkdown notebook. This document has a discussion of seismic induced degradation or diversion of fire suppression systems and the walkdown checklists include a specific section to check for these situations. The aspect of the finding not included in the documentation is a discussion of the spurious operation of detection systems.	This is a documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
4-4	Overcurrent coordination and protection analysis was not reviewed in detail for the FPRA. As a result, additional circuits and cables whose failure could challenge power supply availability due to inadequate or unanalyzed electrical overcurrent protective device coordination were not added to the FPRA. Additionally, power supplies credited in the FPRA using assumed cable routing did not include consideration for possible coordination issues. As a result, all areas that may impact these power supplies may not have been identified.	CS-B1	ANALYZE all electrical distribution buses credited in the Fire PRA plant response model for proper overcurrent coordination and protection and IDENTIFY any additional circuits and cables whose failure could challenge power supply availability due to inadequate electrical overcurrent protective device coordination. Include in this analysis, all buses credited through assumed routing.	Open: The FPRA documentation does not include details of the review of electrical overcurrent protective device coordination calculations. A detailed review of the calculations has been performed. The AC and DC electrical systems, Class 1E and non-Class 1E, are coordinated with the exception of some 208/120V panels. For these panels, the applicable cables are assumed to fail the panels in the FPRA. Additionally, the review of the calculations did not identify instances where cable length was used to show coordination.	This is a documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
4-6	The FPRA HRA notebook indicates that: an action is not likely to be taken based on a single spurious signal. As a result, no new, undesired operator actions that could result from spurious indications resulting from failure of a single instrument, were identified. The FPRA does not include a review of alarm response procedures or similar for potential alarms that may lead to equipment shutdown, alignment changes, or other operator actions that could impact the ability to safely shut down the reactor. As a result, this SR is considered not met to CC II. An operator interview performed during the peer review on this subject indicated that the operator would 'believe their indications' even during a fire, and would perform the actions in response to an alarm in a similar manner as during a non-fire event. In essence, critical equipment would not be shutdown, but other equipment would likely be stopped if a specific trouble alarm occurred. Overall, the interview confirmed that the general assumption in the LGS FPRA for not modeling shutdowns due to spurious alarms is not supported.	HRA-A3	Systematic Issue. Use of a generic argument that operators would basically question each alarm and locally verify all spurious alarms does not appear to meet the intent of CC II of the standard (See SR HRA-A3) or CC I or II for ES-C2.	Partailly Resolved - Not assessed by independent review team: As part of the FPRA update, more than 1500 Alarm Response Cards (ARCs) were reviewed. Of these, about 500 ARCs were identified to be potentially important to the FPRA and were reviewed in detail. The detail review resulted in ~50 ARCs that may lead to an undesired operator action that would trip or isolate a piece of equipment given the alarm even if the equipment was not damaged by fire. Of the 50 ARCs identified, the worst case scenario is where the equipment is tripped or isolated given a spurious alarm. In each of the identified case sufficient time is available for recovery of the equipment if there is not fire damage to the equipment. Therefore, modeling the undesired operator action would consist of the recovery of the equipment, as well. The significance of the undesired action and the failure to recover is estimated to be negligible when compared to the fire induced failures of the equipment and the random failures of the equipment.	The minor model changes will have no material impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
4-27	The basic events added to the FPRA are documented in the UREs (e.g., see table 3-1 of ASM-03). However, the details are not provided in the FPRA documentation. For example, the SRV maintenance probability was changed from 1E-02 to 1E-03 under URE LG2011-038. However, the basis is not included in the FPRA documentation. Additionally, the basic events added in the documentation are not referenced to the UREs, and tracing each basic event to the individual UREs is difficult to perform. It is not clear from the review of the ASM notebook that all events are documented in the UREs. For example, AHUXTRDXD is listed in the HUMAN ERROR PROBABILITY FAULT TREE, but it is not clear what URE is used. Another example, JRM19BMMI0, is documented in 3.1.1.2.2 (RHRSW Loop B radiation monitor miscalibration basic event), but the basis of the event is not provided. Many of the FPRA basic events are based on failure rates, with exposure or run times. However, there is no documentation of the exposure and run times in the documentation. Overall, the basis for new basic events in the FPRA is not documented sufficient to meet the DA-A/B requirements of the standard.	PRM-B13 (DA-A4)	Systematic Issue. None of the BEs provided in the ASM notebooks have references or details.	OPEN: The ASM notebook lists new basic events added to the fire PRA model. There are some that have non-fire random failure probabilities, which are the only ones that this Finding applies to. As noted in the finding, these are only listed in summary form in the ASM notebook. A spot check was performed to determine whether the detailed information on these basic events, type codes, and associated plant specific data was documented in the Data Analysis Notebook (LG-PRA-010). It was determined that this information is not provided, so the Finding is not resolved The finding is related to providing better documentation of the review that was performed.	This is a documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
4-30	The LGS method appears to include the following inconsistencies with the NUREG/CR-6850 method: Air compressors counted include the EDG Starting air compressors and misc. compressors. The total count should only include the service and instrument air compressors. Bin 19 includes the Containment hydrogen recombiner package and Containment H2 Recombiner Skid; which does not normally include hydrogen. However, no other misc. hydrogen fires are postulated. Bin 18 fires are listed as partitioned based on the cable amount in each area, but are set to zero in the ISDS Bin 17, Hydrogen tanks, is listed with a frequency as applicable to LGS, but no sources are identified in the ignition counting. Bin 13, dryers, are listed as applicable to LGS with a frequency, but none are counted. Bin 16d (Isophase bus ducts) is not counted in the ISDS or assigned to a specific PAU.	IGN-A7	Correct discrepancies in the ignition frequency apportionment per the description of this F&O.	Partially Resolved: The Ignition Frequency Notebook (LG-PA-021.56) documents the method used for ignition source counting. The counting for air compressors (bin 9), misc. hydrogen fires (bin 19), and iso-phase bus ducts (bin 16.2) were revised, as suggested by the Peer Review, and in accordance with the methods from NUREG/CR-6850. Those bins with zero frequencies are justified in Section 3.1.7 and Appendix B, such as RCPs (bin 2), self-ignited cable fires (bin 12), dryers (bin 13), and hydrogen tanks (bin 17). The F&O response for junction boxes (bin 18) indicates that the fire risk from junction boxes are not included because the risk is negligible. The FAQ 13-006 is referenced, however it has not been implemented. The F&O response seems to indicate that the F&O is "Open" for junction box fires. The Exelon PRA team indicated that junction box fires will be added to the FPRA consistent with the industry guidance in FAQ 13-0006.	The finding will be resolved and reflected in the next FPRA update, but the changes will be minimal such that there is no material impact on this application.

TABLE A-2
STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
4-33	Reviewed MCA scenarios do not include detailed modeling, including the use of multiple HRRs, fire growth, decay, etc. in the analysis. For example, scenario 020_FZZ1-4 from PAU 20 to 22 (Cable spread room) assumes all PAU 20 fire scenarios (and their associated Ignition frequencies), if not suppressed, will result in a HGL in PAUs 20 and 22. These include cabinet fires, inverters and transients. In this case, the cable trays are located above several cabinets, where fairly small cabinet fires may result in overhead cable tray fires. However, additional detailed analysis could be performed to determine which cabinets would not cause this issue, calculation of the fire growth in the cabinet and cable trays, calculation of the HGL timing, analysis of the HRR for transient fires that can cause a HGL, and other steps discussed in FSS C1-8. Other MCA scenarios include HGL Severity Factors. However, it does not appear that a 2-point fire model was used, or additional factors such as growth and decay, etc.	FSS-C1	For significant fire scenarios, apply detailed fire modeling to each scenario as described in SRs FSS-C1 to C-8.	Open: LG-PRA-021.07.04 (MCA - Multi-Compartment Analysis Notebook) and LG-PRA-021.07.02 (FMT – Fire Modeling Treatments Notebook) state that detailed fire modeling for multi-compartment scenarios is performed, consistent with the fire modeling performed for single compartment analyses. For an MCA scenario, the inputs for the detailed fire modeling of the exposing fire zone are used. The resolution to the example from the F&O is that an MCA scenario from PAU 20 (inverter room) to 22 (cable spreading room) is screened since both rooms lead to abandonment scenarios. The portion of the F&O not resolved is documentation and justification of which ignition sources within the PAU are contributing to the ignition frequencies for the MCA scenario.	The remaining aspect is a FPRA documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
4-34	The ignition frequencies used in the scenario analysis do not include the ignition source data sheets, and support for the differences is not provided. In reviewing the results of several scenarios with the PRA staff, the reason appears to be the removal of some sealed electrical cabinets (explained in the scenario description) as well as, and more importantly, the removal of the transient fires from consideration. For example, scenario 020_FZZ1-4 is listed in the IGN notebook as having a total frequency of 8.22E04/year with 18 cabinets. The MCA scenario sheet in the FSS report however does not list all the cabinets, and uses a 2.30E-04/year ignition frequency. In this case, the transient scenarios are not analyzed, nor are they included in any detailed fire scenario for PAU 20. Similarly, PAUs 12, 13, 25, 39, includes no analysis of transient fires. These are both examples, but in both cases fire scenarios similar to the ones analyzed can occur as a result of transient fires. For area 20, the scenarios involving ignition of overhead cable trays can occur as a result of a large transient fire under or near a cable tray, or by ignition of a cabinet adjacent to the transient fire. Review of the documentation did not indicate any specific basis or analysis supporting the screening of these transient fires.	FSS-G1	Include transient fire scenarios in all areas through either detailed analysis of the scenarios or analysis to demonstrate the transient sources cannot damage equipment or cables.	Open: The finding has not been addressed. The current finding states that the documentation did not indicate any specific basis or analysis supporting the screening of these transient fires. The documentation still does not provide such justification. The finding is related to providing better documentation of the review that was performed.	This is a documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
4-35	The MCA notebook includes both qualitative and quantitative screening criteria. The qualitative screening includes a number of scenarios where it is considered unlikely to have a large transient fire in the area. In comparing this to the Ignition frequency calculations, these areas do not have negligible transient frequencies. The qualitative argument associated with no possible transient of concern appears subjective, and basically infers an argument of a low HRR in these areas in comparison to others. However, there is little basis for this subjectivity given. Note that the recent ERIN approach for adjusting transient HRRs was recently reviewed by the Industry Fire PRA methods panel, and adjustment is possible but is required to be supported by review of transient packages possible in each area. See screening criteria 2.08 and any area with NO listed in Table A-3 of the MCA for 237 kw fires.	FSS-G2	Include in the MCA screening process all transient related fires in each analyzed PAU. If a lower HRR or lower frequency is assumed for selected areas, support for these assumptions should be provided.	Open: Page 3-6 of FMT (Fire Modeling Treatments) notebook, transient fires of 60 kW and 140 kW are considered representative for transients in small areas that lack the space for storage and multiple pieces of equipment to perform maintenance on. Documentation is needed that identifies the locations with the low HRR transient fires and provides justifications regarding the size of the areas, the equipment requiring maintenance, and typical transient packages for the PAUs. The finding is related to providing better documentation of the review that was performed.	This is a documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
4-47	The FPRA used the Level II parameters, which included characterization of the accident progression phenomena including realistic estimates for significant accident sequences. However, a review of the parameters such as DW/WW integrity, containment flooding, WW venting, RB effectiveness, timing for declaring of emergency (including failure to do so) and other parameters was not performed. Reviews at similar plants indicated fire induced impacts of DW and WW Integrity, including containment flooding, WW venting, and fire induced failures of support systems and cooling. Example events from the Quantification Importance Measures (> 1E-02 F-V) include B–OPDHR-EAL2F–, 1DIPH-DI1—S–, 1ISHUOPNEQLINH–, BPHCFXDXI, 1CZOPO2ADD—H–, 1CZPH-STINRT-S–, and numerous others. Several of these appear to be potentially affected by the fire, and the importance measures also include HEPS not included in the Level 1 PRA.	FQ-D1 (LE-E2)	Systematically review the LGS Level II PSA Analysis including parameters impacting the characterization of the accident progression phenomena for potential impact due to fire, and modify the model based on these impacts.	Open: Reviewed Section 3.9.3 of the Plant Response Model Notebook, LG-PRA-021.55. That section describes the process to ensure that the LERF analysis is appropriate for the fire scenarios included in the fire PRA model. The following is considered: In addition, Section 4.8 and Appendix E of the Plant Response Model Notebook discuss the handling of the LERF analysis. The MCRAB analysis sequences are the only new sequences in comparison to the FPIE PRA model. The other Level 2 sequences are the same as used in the FPIE PRA model and BE Mapping accounts for the fire induced failures of components modeled in those sequences. The finding is related to providing better documentation of the review that was performed.	This is a documentation issue with no impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
4-50	LG-PRA-021.05 Section 13.0 and Appendix D provides the methodology and results of the application of conditional probabilities. Methodology follows industry guidance per NUREG/CR-6850 and supplement 1. Uncertainty is qualitatively discussed in LG-PRA-021.01, Table 5-1. However, the uncertainty parameters for the CF probabilities is not provided in the FPRA documentation or included in the CAFTA RR file for propagation through the uncertainty calculations.	CF-A2	Include uncertainty parameters for the CF values used in the FPRA.	Partially Resolved: Section 3.3 of LG-PRA-021.12 (Uncertainty and Sensitivity Notebook) details the uncertainty analysis. Section 3.4.4 of LG-PRA-021.12 lists the calculation of the variance for the beta distributions. The beta uncertainty parameters from NUREG/CR-7150 Vol 2 were used to calculate the variance and applied against the type code based in the .rr file for each spurious operation and duration events. Basic events were verified to be linked to the appropriate type codes. CAFTA files were reviewed and appropriate uncertainty parameters were assigned to type codes for spurious probabilities and spurious duration probabilities for all circuits except for the ungrounded DC circuit breaker aggregate. Upon discussion and review with Exelon engineers, it was determined that a gamma distribution was incorrectly calculated for the ungrounded DC circuit breaker aggregate in the current model.	Fully addressing this finding will have negligible impact on the results. Therefore, there is no material impact on this application.

TABLE A-2

STATUS OF REMAINING OPEN AND PARTIALLY RESOLVED FPRA FINDINGS

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	FINDING BASIS / PROPOSED RESOLUTION	CURRENT STATUS / INDEPENDENT REVIEW TEAM COMMENT	IMPORTANCE TO APPLICATION
6-10	Individual fire modeling references generally provide qualitative uncertainty treatment and in some cases sensitivity studies. The individual fire sources are treated in the fire scenario workbook, Attachment B. Statistical representations are not provided.	FSS-E3	Provide statistical representations of the uncertainty intervals for the parameters used for modeling the significant fire scenarios.	Open - Not assessed by independent review team: The FPRA does not include the fire modeling parameter uncertainty. Statistical representations were provided for the scenario frequencies, non-suppression probabilities, and severity factors. Extending the uncertainty evaluations to the fire modeling inputs for significant fire scenarios would not significantly impact the results of the final uncertainty analysis.	The minor modeling changes will have no material impact on this application.
6-12	Fire modeling outputs are documented in Scenario Development Report and applicable fire modeling documents. The parameter uncertainty of the output is not analyzed for each fire scenario established fire scenario as is required for Cat II.	FSS-H5	Ensure Fire Modeling output is analyzed for each fire scenario as required by SR FSS-H5 including the results of parameter uncertainty evaluations.	Open - Not assessed by independent review team: The FPRA does not document the fire modeling parameter uncertainty. The finding is related to finding 6-10.	This is a documentation issue with no impact on this application.

Seismic Hazards

A seismic CDF PRA model is not maintained for Limerick. As noted in Section 5.7.3 of the main body of the LGS ILRT risk assessment, recent NRC work documented in Reference 27 of the main body provides seismic CDF information. The updated 2008 USGS Seismic Hazard Curves provide a weakest link CDF model. Table D-1 lists the postulated core damage frequencies using the updated 2008 USGS Seismic Hazard Curves. The weakest link model using the curve for LGS resulted in a CDF of 5.3E-05/yr. As noted in Section 5.7.1.2, this is an extremely conservative value, and as such, half of that value (2.65E-05/yr) is used for bounding purposes. The seismic CDF chosen is judged to be sufficient to support an order of magnitude LGS ILRT external events risk impact assessment.

A.2.6 PRA Quality Summary

Based on the above, the LGS FPIE PRA is of sufficient quality and scope for this application. The modeling is detailed; including a comprehensive set of initiating events (transients, LOCAs, and support system failures) including internal flood, system modeling, human reliability analysis and common cause evaluations. The LGS PRA technical capability evaluations and the maintenance and update processes described above provide a robust basis for concluding that these PRA models are suitable for use in the risk-informed process used for this application.

The Fire PRA Model results and the adjusted seismic CDF from the weakest link model using updated 2008 USGS Seismic Hazard Curves are judged to be adequate in performing a bounding “order of magnitude” assessment of ILRT impact.

A.3 IDENTIFICATION OF KEY ASSUMPTIONS

The methodology employed in this risk assessment followed the EPRI guidance as previously approved by the NRC. The analysis included the incorporation of several sensitivity studies and factored in the potential impacts from external events in a bounding fashion. None of the sensitivity studies or bounding analysis indicated any source of uncertainty or modeling assumption that would have resulted in exceeding the acceptance guidelines. The accepted process utilizes a bounding analysis approach, mostly driven by that CDF contribution which does not already lead to LERF. Therefore, there are no key assumptions or sources of uncertainty identified for this application (i.e. those which would change the conclusions from the risk assessment results presented here).

A.4 SUMMARY

A PRA technical adequacy evaluation was performed consistent with the requirements of RG-1.200, Revision 2 [A.1]. This evaluation combined with the details of the results of this analysis demonstrates with reasonable assurance that the proposed extension to the ILRT interval for LGS Unit 1 and Unit 2 to fifteen years satisfies the risk acceptance guidelines in RG 1.174 [A.9].

A.5 REFERENCES

[A.1] Regulatory Guide 1.200, *An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk Informed Activities*, Revision 2, March 2009.

[A.2] ASME, *Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications*, Draft Addendum B to ASME RA-Sa-2003, June 2005.

[A.3] ASME, *Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications*, (ASME RA-S-2002), Addenda RA-Sa-2003, and Addenda RA-Sb-2005, December 2005.

[A.4] Regulatory Guide 1.200, *An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk Informed Activities*, Revision 1, January, 2007.

[A.5] JENSEN HUGHES, *Limerick Generating Station PRA Finding Level Fact and Observation Technical Review*, Report 032156-RPT-001, August 2016.

[A.6] ASME/American Nuclear Society, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications, ASME/ANS RA-Sa-2009, March 2009.

[A.7] NEI, *Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines*, NEI 07-12, Revision 1, June 2010.

[A.8] Electric Power Research Institute, *Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals: Revision 2-A of 1009325*, EPRI TR-1018243, October 2008.

[A.9] U.S. Nuclear Regulatory Commission, *An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis*, Regulatory Guide 1.174, Revision 2, May 2011.

Appendix B

BYPASS LEAK RATE TEST RISK ASSESSMENT

B BYPASS LEAK RATE TEST RISK ASSESSMENT

Note that the methodology to evaluate the impact of concurrently extending the DWBT interval is performed consistent with the previous one-time ILRT/DWBT extension for Limerick [B.1], but has been updated to reflect more recent information.

Background

The following steps are used to perform the analysis for the DWBT interval extension:

- Review the design basis
- Review historical test results
- Develop qualitative technical justification of change
- Perform deterministic calculations
- Perform risk assessment of interval change

B.1 LGS MARK II PRESSURE SUPPRESSION CONTAINMENT DESIGN

LGS incorporates a Mark II containment with the drywell located over the suppression chamber and separated by a diaphragm slab. The suppression chamber contains a pool of water having a depth that varies between 22' and 24'-3" during normal operation. Eighty-seven downcomers and 14 main steam safety/relief valve (SRV) discharge lines penetrate the diaphragm slab and terminate at a pre-designed submergence within the pool. During a loss of coolant accident (LOCA) inside containment, the containment design directs steam from the drywell to the suppression pool via the downcomers through the pool of water to limit the maximum containment pressure response to less than the design pressure of 55 psig. The effectiveness of the LGS pressure suppression containment requires that the leak path from the drywell to the suppression chamber airspace be minimized. Steam that enters the suppression pool airspace through the leak paths will bypass the suppression pool and can result in a rapid post-LOCA increase in containment pressure depending on the size of the bypass flow area.

The design value for leakage area is determined by analyzing a spectrum of LOCA break sizes. For each break size there is a limiting leakage area. In determining the limiting leakage area, credit is taken for the capability of operators to initiate drywell and suppression pool sprays after a period of time sufficient for them to realize that there is a significant bypass leakage flow. The effect of suppression pool bypass on containment pressure response is greatest with small breaks. The design value of 0.0500 ft^2 for LGS represents the maximum leakage area that can be tolerated for that break size that is most limiting with respect to suppression pool bypass.

Limerick Tech Spec (TS) requirements conservatively specify a maximum allowable bypass area of 10% of the design value of 0.0500 ft^2. The TS limit provides an additional factor of 10 safety margin above the conservatisms taken in the steam bypass analysis. The drywell-to-suppression chamber bypass test verifies that the actual bypass flow area is less than or equal to the TS limit.

B.2 HISTORICAL TEST RESULTS

A review of the past test history for the drywell-to-suppression chamber bypass leakage test has identified no failures. The following are the test results [B.1, B.6]:

Unit 1 (Acceptance - 0.005 sq. ft.)	Unit 2 (Acceptance - 0.005 sq. ft.)
1984 - 0.00026	1989 - 0.000069
1987 - 0.00005133	1993 - 0.000076
1990 - 0.000278	1999 - 0.000012
1998 - 0.000075	2013 – 0.000137
2012 – 0.000151	

The history of test results indicates that the typical leakage is about an order of magnitude or more below the acceptance criteria (which is set at an order of magnitude below the design basis limit). This excellent history combined with the conservatism included in the allowable leakage rate helps to support the qualitative justification provided below, and also helps support the low likelihood of a large undetected bypass leakage in the risk assessment.

B.3 QUALITATIVE JUSTIFICATION FOR DWBT INTERVAL EXTENSION

Several potential bypass leakage pathways exist:

- Leakage through the diaphragm floor penetrations (SRV discharge line downcomers),
- Cracks in the diaphragm floor/liner plate,
- Cracks in the downcomers that pass through the suppression pool airspace,
- Valve seat leakage in the four sets of drywell-to-suppression chamber containment vacuum breakers, and
- Seat leakage of isolation valves in piping connecting the drywell and the suppression chamber air space.

A previous assessment [B.2] demonstrated that the most likely source of potential bypass leakage is the four sets of drywell-to-suppression chamber vacuum breakers. Each set consists of two vacuum breakers in series, flange mounted to a tee off the downcomers in the suppression chamber airspace. The drywell-to-suppression chamber bypass leak test is currently performed on a schedule consistent with the ILRT. However, TS 4.6.2.1.f requires that the vacuum breaker leakage tests on all four sets of vacuum breakers be performed on all non-ILRT outages. Therefore, the most likely largest contributor to the bypass leakage will still be monitored each refueling outage and therefore will continue to be managed and controlled to assure Tech Spec leakage is maintained.

The vacuum breaker leakage test and stringent acceptance criteria, combined with the historical negligible non-vacuum breaker leakage, and thorough periodic visual inspection provide an equivalent level of assurance as the DWBT that the drywell to suppression chamber bypass leakage can be measured and any adverse condition detected prior to a Loss of Coolant Accident (LOCA).

B.4 DETERMINISTIC CALCULATIONS

As part of the risk assessment of the DWBT interval extension, a set of deterministic thermal hydraulic analyses have been performed to identify the impact of increased drywell to suppression chamber leakage on the risk spectrum [B.5].

Table B-2 summarizes the results of the deterministic thermal hydraulic analyses using the LGS specific plant model (i.e., MAAP model). The results in Tables B-2 focus on the response of containment pressurization to water and steam LOCA events as a function of the drywell to suppression chamber bypass leakage.

Tables B-2 displays the following key results from this analysis and the impact of increased drywell to suppression chamber bypass leakage:

- As shown in the table, steam LOCAs are a greater challenge than water LOCAs.
- Medium and large steam LOCA events challenge the ultimate containment pressure (~140 psig) capability for a leakage size of 100x Tech Spec leakage. The steam events have the potential to result in core damage and a Large Early Release (LERF) event. The time to drywell failure ranges from 2.0 to 2.2 hours.
- Small steam LOCA events do not exceed the ultimate containment pressure (~140 psig) capability for a leakage size of 100x Tech Spec leakage for a 24 hour mission time. However, it is noted that some additional mitigation measures would be required to achieve a safe and stable state for the small steam LOCA initiators.
- A water LOCA event with a concurrent drywell bypass leakage of size 100x TS leakage does not challenge the ultimate containment pressure limit. Therefore, CDF associated with water break LOCAs and bypass leakage up to 100x TS leakage is not affected because adequate vapor suppression is present.
- The vacuum breaker failure-to-close bypass cases (600x TS leakage) are run for information.

It should be noted that there are simple crew actions that can successfully mitigate the containment pressurization observed in the LOCA cases:

- Use of drywell sprays
- Emergency depressurization

Both actions are called for by the LGS TRIPs and neither system is adversely impacted by the small LOCA initiating event. As can be seen in Table B-2, the large and medium small steam LOCA events would reach the ultimate containment pressure in about two hours. This would provide operators ample time to provide mitigation measures. For the small steam LOCAs, even more time would be avialable such that that the TSC is operational and actions according to the EOPs will be taken with a high degree of certainty, comparable to the certainty applied to the initiation of RHR.

In conclusion, for a full range of water LOCAs, variations in the drywell to suppression chamber bypass leakage, from zero to many times Tech Spec leakage, do not impact the vapor suppression capability of the LGS containment and therefore do not significantly impact the calculated CDF or radionuclide release frequency for these accident scenarios. For the medium and large steam LOCAs the results indicate that the containment pressure approaches exceeds the the ultimate containment pressure within a few hours. For small steam LOCAs, the containment pressure approaches the ultimate containment pressure within the 24 hour mission time. For simplicity, an operator action to initiate containment sprays or perform an emergency depressurization is assumed to be required to prevent containment overpressure failure for a leakage of this magnitude. These conclusions regarding the impact of the potential for increased drywell to suppression chamber leakage are factored into the risk assessment.

TABLE B-2

CONTAINMENT PRESSURE RESPONSE FOR LOCA INITIATORS AS A FUNCTION OF DRYWELL TO WETWELL BYPASS LEAKAGE

	DRYWELL PRESSURE (PSIG)						TIME TO DRYWELL FAILURE AT 140 PSIG (HOURS)	
	INITIAL PEAK		AT 5 HRS		AT 24 HRS			
MAAP Case[(1)(2)]	STEAM	WATER	STEAM	WATER	STEAM	WATER	STEAM	WATER
SLOCA-0L	--	--	35.4	33.4	50.8	44.6	N/A	N/A
SLOCA-10L	--	--	45.5	42.4	66.4	45.8	N/A	N/A
SLOCA-100L	--	--	102.7	40.9	121.6	45.5	N/A	N/A
SLOCA-600L[(3)]	--	--	103.2	40.9	121.2	45.2	N/A	N/A
MLOCA-0L	30.1	29.6	33.3	13.6	42.5	25.2	N/A	N/A
MLOCA-10L	33.2	32.0	43.8	13.7	66.9	23.0	N/A	N/A
MLOCA-100L	72.8	59.4	--	15.5	--	22.5	2.0 hrs	N/A
MLOCA-600L[(3)]	>140	132.0	--	21.3	--	20.4	0.9 hrs	N/A
LLOCA-0L	27.0	22.5	32.5	10.4	46.9	16.6	N/A	N/A
LLOCA-10L	29.4	22.7	42.5	10.6	66.0	16.7	N/A	N/A
LLOCA-100L	>140	25.2	--	10.8	--	16.8	2.2 Hrs	N/A
LLOCA-600L[(3)]	>140	37.2	--	12.4	--	16.9	1.8 hrs	N/A

Notes to Table B-2:

(1) MAAP cases run with RHR in suppression pool cooling mode and no containment sprays actuated.

(2) Case IDs: 0L cases indicate no DW to SP bypass, 10L and 100 L run with 10x and 100x Tech Spec leakage from DW to WW respectively.

(3) LOCA with ECCS available and stuck open vacuum breaker (600x Tech Spec leakage from DW to WW).

B.5 RISK ASSESSMENT

The Drywell to Suppression Chamber leakage can lead to the following perturbations on risk metrics:

- The increase in leakage could result in an increase in the failure probability of the vapor suppression function and consequential failure of containment. This could lead to pool bypass and core damage.
- The bypass leakage would result in an increase in the radionuclides in the suppression chamber airspace following an RPV breach if drywell sprays were unavailable. This could result in increased radionuclide release for suppression chamber breach cases or suppression chamber (wetwell) vent cases with core damage and no drywell failure or other pool bypass mechanisms.

The following steps are used for the risk assessment:

1. Determine sequences that are impacted by changes in bypass area.
2. Calculate probability of large bypass area.
3. Calculate risk metrics for original bypass test interval.
4. Calculate risk metrics for 10 year bypass test interval.
5. Calculate risk metrics for 15 year bypass test interval.
6. Summarize the changes in the calculated risk metrics.

Step 1 - Determine Sequences Impacted by Changes in Bypass Area

As shown in the deterministic calculations, the only accident sequences that are impacted by the DWBT interval extension are those severe accidents induced by a loss of containment integrity due to overpressure failure. Additionally, it was shown that the only potential contributors to this situation are small, medium, and large steam LOCAs that have sufficiently high bypass leakage to allow continual containment pressurization coupled with no mitigating actions.

Loss of containment from over pressurization with adequate vessel inventory make-up prior to failure, has the potential to cause loss of inventory make-up upon containment failure leading to core damage. This assessment will conservatively assume that all injection is lost if containment failure occurs due to over pressurization afforded by drywell bypass leakage.

Additionally, it is acknowledged that some accident scenarios that are currently classified as early wetwell region failures have the potential to be re-categorized as LERF due to the presence of a large bypass area that would render the fission product scrubbing capabilities of the suppression pool ineffective in reducing the source term below LERF threshold values. These potential scenario changes will also be accounted for in this analysis.

Finally, it is noted that the potential exists for increased drywell to suppression chamber bypass leakage to have an impact on the likelihood that early containment failure occurs. For example, in an SBO scenario (i.e., loss of all injection),molten debris in contact with significant volumes of water shortly after vessel failure could maximize the amount of steam generation resulting in a deleterious impact of the bypass leakage. The LGS Mark II containment design incorporates a pedestal directly below the RPV. This pedestal area would be expected to be dry unless containment sprays were operating prior to the time of vessel failure. The pedestal floor has drain pipes that are estimated to fail by core interaction shortly after of vessel failure resulting (i.e., within 7 minutes) in a drywell to wetwell airspace pathway. The drain pipe pathway failure would exceed the postulated DWBT drywell to wetwell leakage area and would render a pre-existing drywell to wetwell leakage moot. As such, the risk assessment assumes that there is no increase in LERF from this potential accident scenario (i.e. LERF due to early containment failure from drywell bypass vapor suppression failure near the time of vessel failure) due to changing the DWBT interval.

Step 2 - Calculate Probability of Large Bypass Area

Industry and LGS experience with the results of the DWBT has been quite good. However, for simplicity and for consistency with the ILRT analysis for LGS, it will be assumed that the base case potential for a large drywell to suppression chamber bypass leak (100La) is the same as was utilized for the ILRT analysis (i.e. 0.0023).

Additionally, consistent with the EPRI Guidance [B.3], the change in the probability of a large undetected bypass increases by a factor of 3.33 for a ten-year interval and an extension to a 15 year interval can be estimated to lead to a factor increase of 5.0 in the non-detection probability of a leak.

Step 3 - Calculate the Risk for the 3 in 10 Year Bypass Leak Rate Test Interval

The LGS base case did not include DW to WW bypass failure. Therefore the frequency of the Base Case model is adjusted to incorporate the severe accident frequency.

As described in Step 2, the probability of a "large" bypass given the original DWBT interval and excellent historical test experience is assumed to be 0.0023. Thus, the CDF to be added to the base model is:

$$\begin{aligned}\Delta CDF = \; & (\text{Small Steam LOCA}) * (\text{Large Bypass Leak Probability}) * \\ & (\text{DW Spray Failure Probability} * \text{Emergency Depressurization})_{SLOCA} + \\ & (\text{Medium Steam LOCA}) * (\text{Large Bypass Leak Probability}) * \\ & (\text{DW Spray Failure Probability} * \text{Emergency Depressurization})_{MLOCA} + \\ & (\text{Large Steam LOCA}) * (\text{Large Bypass Leak Probability}) * \\ & (\text{DW Spray Failure Probability} * \text{Emergency Depressurization})_{LLOCA}\end{aligned}$$

Where the applicable LOCA(1) initiating event frequencies are taken from the current LGS PRA model. Addtionally, given the extremely long time avaialble to take mitigative measures in the small steam LOCA case, a bounding value of 1E-4 is utilized to represent the combined fialure probabililty of the DW spray failure probability and emergency depressurization actions. This bounding value accounts for both operator action dependencies and hardware failures. Given the approximate two-hour time frame available in the medium and large steam LOCA scenarios, a factor of ten higher value is

(1) LOCA frequencies are as follows:
Small Steam LOCA (2.04E-04/yr)
Medium Steam LOCA (5.76E-05/yr)
Large Steam LOCA (7.45E-06/yr)

utilized (i.e., 1E-3 combined failure probability). Thus, the calculated increase in CDF is as follows.

ΔCDF_{SLOCA} = 2.04E-04/yr * 0.0023 * 1.0E-04 = 4.69E-11/yr
ΔCDF_{MLOCA} = 5.76E-05/yr * 0.0023 * 1.0E-03 = 1.32E-10/yr
ΔCDF_{LLOCA} = 7.45E-06/yr * 0.0023 * 1.0E-03 = 1.71E-11/yr

ΔCDF = 4.69E-11/yr + 1.32E-10/yr + 1.71E-11/yr = 1.97E-10/yr

Assuming all of this increase also leads to a large and early release, adjustments can also be made to EPRI Category 2 for the "new" LERF contribution from these small, medium and large steam LOCAs. However, as can be easily seen, the "new" contributors to CDF and LERF are negligible compared with the previously assessed base case, and will not have any measurable impact on the results.

<u>Change in LERF for Existing Sequences</u>

The potential change in LERF is limited to those accident scenarios that were previously classified as early wetwell region failures in Category 7. This contribution can be conservatively represented by the Low-Early (L/E) and Medium-Early (M/E) contributions assigned to APB#1 and APB#2. That is, it will be conservatively assumed that all previous L/E and M/E contributions from APB#1 and APB#2 would be H/E release given a DWBT leakage of 100La.

ΔMedium-Early (M/E) = ($M/E_{Original}$ from APB#1) * Large Bypass Leak Probability

= (1.51E-07/yr) * 0.0023 = 3.47E-10/yr

ΔLow-Early (L/E) = (L/EOriginal from APB#2) * Large Bypass Leak Probability

= (1.54E-07/yr) * 0.0023 = 3.55E-10/yr

These L/E and M/E will be assumed to represent a change in LERF and the contributions will be removed from Category 7 contributions and moved to Category 2 (Isolation Bypass Failure).

$$\Delta\text{EPRI Class 2} = \Delta\text{Medium-Early (M/E)} + \Delta\text{Low-Early (M/E)}$$

$$= 3.47\text{E-10/yr} + 3.55\text{E-10/yr} = 7.02\text{E-10/yr}$$

For the purposes of this assessment, the changes to EPRI Classes 3a and 3b from the ILRT interval extension will be ignored so as to isolate the potential impact of the changes on the DWBT interval extension. With the population dose information derived for LGS as shown in Table 5.2-2 of the ILRT portion of the LGS submittal, with the initial EPRI Class 2, and 7 frequency information obtained from the detailed information that was used to support the development of that table, and with EPRI Class 1 assigned the remaining CDF from the total, the revised base case results showing the adjustments to Class 2, and 7 as described above are shown in Table B-3.

TABLE B-3
QUANTITATIVE RESULTS AS A FUNCTION OF ORIGINAL DWBT INTERVAL FOR 3 IN 10 YEARS FREQUENCY

EPRI CLASS	DOSE (PERSON-REM WITHIN 50 MILES)	ORIGINAL DWBT INTERVAL	
		ACCIDENT FREQUENCY (PER YEAR)	POPULATION DOSE RATE (PERSON-REM/YEAR WITHIN 50 MILES)
1	1.56E+04	3.45E-07[2]	5.37E-03
2	9.35E+06	9.78E-09 + 1.97E-10 + 7.02E-10 = 1.07E-8	9.99E-02
3a	1.56E+05	-	-
3b	1.56E+06	-	-
4	N/A	N/A	N/A
5	N/A	N/A	N/A
6	N/A	N/A	N/A
7	6.50E+06	2.80E-06 - 7.02E-10 = 2.80E-06	18.17
8	9.35E+06	6.94E-9	6.49E-02
TOTALS			**18.344**
	CDF	**3.16E-6**	
	CCFP[1]	**89.072%**	

Notes to Table B-3:

(1) Determined from (Class 2 + Class 7 + Class 8) / (Total CDF)

(2) Intact containment CDF w/o subtracting class 3a and 3b contributors.

Step 4 - Calculate the Risk for 10 Year Bypass Leak Rate Test Interval

The risk metrics for the 10 year DWBT interval are the same as the base case from Step 3, except the impact of the bypass leakage is increased by a factor of 3.33 consistent with the ILRT assessment. The revised results are shown in Table B-4.

TABLE B-4
QUANTITATIVE RESULTS AS A FUNCTION OF 10 YEAR DWBT INTERVAL

		10 YEAR DWBT INTERVAL	
EPRI CLASS	DOSE (PERSON-REM WITHIN 50 MILES)	ACCIDENT FREQUENCY (PER YEAR)	POPULATION DOSE RATE (PERSON-REM/YEAR WITHIN 50 MILES)
1	1.56E+04	3.45E-07(2)	5.37E-03
2	9.35E+06	9.78E-09 + 6.55E-10 + 2.34E-09 = 1.28E-08	1.19E-01
3a	1.56E+05	-	-
3b	1.56E+06	-	-
4	N/A	N/A	N/A
5	N/A	N/A	N/A
6	N/A	N/A	N/A
7	6.50E+06	2.80E-06 - 2.34E-09 = 2.80E-06	18.16
8	9.35E+06	6.94E-9	6.49E-02
TOTALS	**CDF** **CCFP(1)**	**3.16E-6** **89.073%**	**18.353**

Notes to Table B-4:

(1) Determined from (Class 2 + Class 7 + Class 8) / (Total CDF)

(2) Intact containment CDF w/o subtracting class 3a and 3b contributors.

Step 5 - Calculate the Risk for 15 Year Bypass Leak Rate Test Interval

The risk metrics for the 15 year DWBT interval are the same as the base case from Step 3, except the impact of the bypass leakage is increased by a factor of 5.0 consistent with the ILRT assessment. The revised results are shown in Table B-5.

TABLE B-5
QUANTITATIVE RESULTS AS A FUNCTION OF 15 YEAR DWBT INTERVAL

EPRI CLASS	DOSE (PERSON-REM WITHIN 50 MILES)	15 YEAR DWBT INTERVAL ACCIDENT FREQUENCY (PER YEAR)	15 YEAR DWBT INTERVAL POPULATION DOSE RATE (PERSON-REM/YEAR WITHIN 50 MILES)
1	1.56E+04	3.45E-07[2]	5.37E-03
2	9.35E+06	9.78E-09 + 9.83E-10 + 3.51E-09 = 1.43E-08	1.34E-01
3a	1.56E+05	-	-
3b	1.56E+06	-	-
4	N/A	N/A	N/A
5	N/A	N/A	N/A
6	N/A	N/A	N/A
7	6.50E+06	2.80E-06 - 3.51E-09 = 2.79E-06	18.16
8	9.35E+06	6.94E-9	6.49E-02
TOTALS	**CDF** **CCFP[1]**	**3.16E-6** **89.075%**	**18.360**

Notes to Table B-5:

(1) Determined from (Class 2 + Class 7 + Class 8) / (Total CDF)

(2) Intact containment CDF w/o subtracting class 3a and 3b contributors.

Step 6 - Summarize the Changes in the Calculated Risk Metrics

Consistent with the ILRT assessment, the relevant figures of merit are change in LERF, population dose, and conditional containment failure probability (CCFP). Additionally, the DWBT extension will also lead to a change in CDF as previously described. The results for these figures of merit from the DWBT interval extension are shown below in Table B-6.

Table B-6
SUMMARY OF QUANTITATIVE RESULTS FOR DWBT INTERVAL EXTENSION REQUEST

FIGURE OF MERIT	ORIGINAL DWBT INTERVAL	10 YEAR DWBT INTERVAL	15 YEAR DWBT INTERVAL
CDF (/yr)	3.160E-06	3.161E-06	3.161E-06
LERF (Class 2) (/yr)	1.07E-08	1.28E-08	1.43E-08
Dose (person-rem/yr)	18.344	18.353	18.360
CCFP (%)	89.072%	89.073%	89.075%
Changes from 3 in 10 yr. interval			
Increase in CDF (/yr)		**4.58E-10**	**7.86E-10**
Increase in LERF (/yr)		**2.09E-09**	**3.60E-09**
Increase in Dose (person-rem/yr)		**0.009**	**0.015**
Increase in CCFP (%)		**0.002%**	**0.003%**

Based on the results of the deterministic studies and their probabilistic risk assessment implications, the following can be defined:

- Increasing the DWBT interval is assumed to increase the probability of increased bypass leakage.
- There is a change in core damage frequency (CDF) associated with the possibility that a steam LOCA occurs with the increased DW to WW bypass leakage and the containment pressurization is not mitigated. This is conservatively assumed to lead to containment failure and consequential loss of RPV makeup and results in core damage.

- There is also a change in the large early release frequency (LERF) associated with the possibility that previous early WW region failures that were not considered LERF due to the fission product scrubbing effects of the suppression pool would be LERF if sufficient bypass leakage area exists.
- The change in population dose associated with the other changes above is noted in Table B-6. The overall change in population dose is very small (~0.1%).
- There is also a change in the conditional containment failure probability (CCFP) with an increase in CDF. It is also noted that the increase in LERF is only from cases that were already containment failure cases (albeit shifted to a LERF release).

The risk metric changes to be compared are then:

Δ CDF	= 7.86E-10/yr
Δ LERF	= 3.60E-09/yr
Δ Person-rem dose rate	= 0.015 person-rem/year
Δ CCFP	= 0.003%

The changes in CDF and LERF meet the Regulatory Guide 1.174 [B.4] acceptance guidelines for very small risk change. The change in population dose rate is well below the acceptance criteria of ≤1.0 person-rem/yr or <1.0% person-rem/yr defined in the EPRI guidance document [B.3]. Change in CCFP of 0.003% is approximately two orders of magnitude below the EPRI guidance document acceptance criteria of less than 1.5%.

The change in the risk metrics associated with the DWBT interval extension calculated above are based on internal events. The changes are very small and would not significantly change even if the potential impact from external events as calculated in Section 5.7.5 of the main body were to be incorporated. That is, the change in CDF is negligible, the change in LERF from the DWBT is about 10% of the change in LERF from the ILRT, the change in person-rem from the DWBT is less than 25% of the change in person-rem from the ILRT extension, and the change in CCFPis just about 3% of the change in CCFP from the ILRT. Given the substantial margin that exists to the acceptance criteria even when external events are factored in, correspondingly including the DWBT results into the external events assessment would not change the conclusions of the analysis. In summary, the change in the DWBT interval extension from 3 in 10 years to 1 in 15 years is found to result in an acceptable change in risk.

B.6 REFERENCES

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[B.2] Letter from G.A. Hunger, Jr. (Philadelphia Electric Company) to U.S. Nuclear Regulatory Commission, *Limerick Generating Station, Units 1 and 2 Technical Specifications Change Request, Dockets No. 50-352 and 50-353*, November 30, 1993.

[B.3] Electric Power Research Institute, *Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals: Revision 2-A of 1009325*, EPRI TR-1018243, October 2008.

[B.4] U.S. Nuclear Regulatory Commission, *An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis*, Regulatory Guide 1.174, Revision 2, May 2011.

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42. NUREG-1339, Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants, dated June 1990

43. NUREG-1801, Generic Aging Lessons Learned (Final Report), Revision 2, dated December 2010

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