VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

June 28, 2002

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

Serial No.	02-312
NL&OS/ETS	R1
Docket Nos.	50-280
	50-338
License No.	DPR-32
	NPF-4

Gentlemen:

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNIT 1
NORTH ANNA UNIT 1
REQUEST FOR ADDITIONAL INFORMATION ON
PROPOSED RISK-INFORMED TECHNICAL SPECIFICATIONS CHANGE
FIVE YEAR EXTENSION OF TYPE A TEST INTERVAL

In letters dated October 15, 2001 and December 7, 2001 (Serial Nos. 01-634 and 01-736), Virginia Electric and Power Company (Dominion) requested amendments to Facility Operating License Numbers DPR-32 and NPF-4 in the form of a change to the Technical Specifications for Surry Power Station Unit 1 and North Anna Power Station Unit 1, respectively. The proposed changes will permit a one-time, five-year extension of the ten-year performance-based Type A test interval established in NEI 94-01, "Nuclear Energy Institute Industry Guideline For Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," Revision 0, July 26, 1995. In telephone conference calls on April 26, 2002 and May 28, 2002, the NRC requested additional information to complete the review of the proposed license amendment requests for Surry and North Anna. The attachments to this letter provide the requested information to support both Surry and North Anna license amendment requests.

Should you have any questions or require additional information, please contact Thomas Shaub at (804) 273-2763.

Very truly yours,

Eugene S. Grecheck
Vice President – Nuclear Support Services

Commitments made in this letter: None

Attachments

A017

cc: U.S. Nuclear Regulatory Commission
Region II
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Suite 23 T85
Atlanta, Georgia 30303

Mr. R. A. Musser
NRC Senior Resident Inspector
Surry Power Station

Mr. M. J. Morgan
NRC Senior Resident Inspector
North Anna Power Station

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Glen Allen, Virginia 23060

Commissioner
Bureau of Radiological Health
1500 East Main Street
Suite 240
Richmond, VA 23218

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Eugene S. Grecheck, who is Vice President - Nuclear Support Services, of Virginia Electric and Power Company. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of that Company, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 28th day of June, 2002.

My Commission Expires: May 31, 2006.

Vicki L. Hull
Notary Public

(SEAL)

Attachment

Request for Additional Information
Proposed Risk-Informed Technical Specifications Change
Five-Year Extension of Type A Test Interval

Surry Power Station Unit 1
Virginia Electric and Power Company
(Dominion)

Proposed Risk-Informed Technical Specifications Change
Five-Year Extension of Type A Test Interval
Surry Request for Additional Information

Since the inservice inspection requirements of 10 CFR 50.55a complement the leak rate testing requirements of Option B of Appendix J in ensuring the leak-tightness and structural integrity of the containment, the staff needs the following information:

NRC Question 1:

In formulating your IWE/IWL program for Surry 1, you considered the first inspection period as five years (September 9, 1996 to September 8, 2001) – the period given to the licensees to complete their first period examinations in 10 CFR 50.55a. In the NRC response to NEI questions 13, 15 and 16 on containment inservice inspections requirements discussed in NRC letter to NEI entitled "Responses to NEI's Topic and Specific Issues Related to Containment Inspection Requirements," dated May 30,1997, the NRC explained that this interpretation of the rule was incorrect. The staff noted that the inspection periods should be determined as required in the ASME Code, Section XI. Please provide your actual start dates of the first and subsequent inspection periods for ASME Code Class CC and MC components in the first interval as required by the ASME Code, Section XI.

Response:

Surry Unit 1 completed its first period IWE examinations on April 25, 2000, and its first interval IWL examinations by August 31, 2001. Using the NRC interpretation found in the reference provided by the NRC Staff, Letter to NEI from the NRC dated May 30, 1997, the Surry Unit 1 IWE and IWL period and interval dates follow.

IWE 1st interval

- 1st period – April 26, 1997 to April 25, 2000
- 2nd period – April 26, 2000 to April 25, 2004
- 3rd period – April 26, 2004 to April 25, 2007

IWL 1st Interval

- September 1, 1996 to August 31, 2001 (five year interval for IWL)

Thus, the start of the second IWE interval will be April 26, 2007 and the start of the second IWL interval will be September 1, 2001.

NRC Question 2:

In the license application, you indicate that for the examination of seals and gaskets, and examination and testing of bolts associated with the primary containment pressure boundary (Examination Categories E-D and E-G), you had requested relief from the requirements of the Code. As an alternative, you plan to examine them during the leak rate testing of the primary containment. With the flexibility provided in Option B of Appendix J for Type B testing and Type C testing (as per NEI 94-01, and RG 1.163), and the extension requested in this amendment for Type A testing, please provide your schedule for examining and testing seals, gaskets, and bolting that assures the integrity of these components.

Response:

Surry Unit 1 IWE Relief Request RR-IWE2 requested relief from the Section XI Code requirement to perform a visual VT-3 examination on seals and gaskets. The alternative accepted is as follows:

> "The leak-tightness of seals and gaskets will be tested in accordance with 10 CFR 50, Appendix J. The 10 CFR 50, Appendix J Type B testing is performed at least once each inspection interval."

Surry Unit 1 performs some portion of the Appendix J Type B tests each refueling outage, staggering the testing to balance the outage work scope. Currently, these tests are completed in approximately 60-month intervals consistent with the Type C testing requirements. The current rule requires completion within 120 months. Thus, the current Surry Unit 1 Type B testing frequency is more conservative.

The relief request basis states that Type B tests will continue to be completed within the 120-month interval and will adequately test the applicable seals and gaskets. The proposed one-time Appendix J, Type A extension will not affect this relief request basis.

Surry Unit 1 IWE Relief Request RR-IWE5 requested relief from the Section XI Code requirement to perform bolt torque or tension tests on bolted connections not disassembled and reassembled during the inspection interval. The alternative accepted is as follows:

> "The following examinations and tests required by Subsection IWE ensure the structural integrity and leak-tightness of Class MC pressure retaining bolting, and therefore, no additional alternative examinations are proposed:
>
> (1) Exposed surfaces of bolted connections shall be visually examined in accordance with requirements of Table IWE-2500-1, Examination Category E-G, Pressure Retaining Bolting, Item No. E8.10, and
>
> (2) Bolted connections shall meet the pressure test requirements of Table IWE-2500-1, Examination Category E-P, All Pressure Retaining Components, Item E9.40."

The required visual examination frequency for Category E-G remains unaffected by the proposed Appendix J, Type A extension and will be completed as required by the

Section XI Code (i.e., 100% in the inspection interval). Item E9.40 references the Appendix J, Type B test requirements, which are discussed above. Again, the Appendix J, Type A extension will not affect this relief request basis or the frequency of performing Type B testing on components with bolting.

NRC Question 3:

The stainless steel bellows have been found to be susceptible to trans-granular stress corrosion cracking, and the leakage through them are not readily detectable by Type B testing, as discussed in NRC Information Notice 92-20. Please provide information regarding inspection and testing of the bellows at Surry 1 and how the potential bellows degradation has been factored into the risk assessment.

Response:

There are two locations where bellows are installed in the Surry containment. A stainless steel bellows is located inside containment on the outer tube of the fuel transfer tube containment penetration. In addition, in-containment Inconel bellows are located on the Service Water System (SWS) discharge piping from each of the four recirculation spray heat exchangers (RSHXs), also located inside containment.

Fuel Transfer Tube Bellows - The bellows inside containment on the outer pipe of the fuel transfer tube only compensates for any differential motion and does not form the containment boundary. The containment boundary is the welded connection at the containment liner to the inner and outer tubes and the double O-ring blank flange on the inner (fuel transfer) tube. The blank flange is Type B tested every refueling outage and the welded connection is tested during the integrated leak rate test (ILRT). A manual isolation valve isolates the inner (fuel transfer) tube from the spent fuel pool in the spent fuel building.

Bellows in Service Water Piping from RSHXs - Service water to the four RSHXs is isolated during normal power operation with closed motor-operated valves (MOVs). On a high-high containment pressure signal, these MOVs will open to provide cooling water to/from the RSHXs. The SWS inside containment to and from the RSHXs is classified as a closed system in accordance with American National Standard ANSI/ANS 56.2-1984. Therefore, the SWS piping to and from the RSHXs is tested as part of the containment boundary during the ILRTs. In addition, the Inconel bellows are tested as part of closed system boundary verification testing performed on the SWS piping inside containment between the inlet and outlet SW MOVs. This test is required if the SWS piping or heat exchangers were breached for testing, maintenance or modification.

Even if a flaw exists in the bellows that went undetected during the last leakage test, it would most likely not have a driving mechanism to propagate through the bellows since the sections of SWS piping containing the bellows are maintained in a dry condition during plant operation to optimize performance of the heat exchangers. Although these sections of piping are maintained in a dry condition, the corrugated shape of the bellows permits accumulation of water and/or debris in the low points of the corrugations. Experience has shown that pitting has occurred in Inconel 600 bellows due to microbiologically influenced corrosion (MIC). Transgranular stress corrosion cracking has not been seen in these bellows. To address this pitting concern, replacement of the four in-containment Unit 1 Inconel 600 bellows has been completed. The replacement bellows are constructed on a more corrosion resistant material, Inconel 625, and have an increased wall thickness. The likelihood of pitting due to MIC is minimized with the Inconel 625 bellows. If such pitting were to occur and progress, it would result in a leak, not a rupture. Additionally, if a leak did occur when the system was in service, radiation monitors in the discharge lines of each subsystem would detect the leak and, as required by emergency procedure, the affected subsystem would be deactivated and isolated by stopping the associated pump and closing the isolation MOVs. These actions would reduce the pressure across the affected subsystem boundary and provide another barrier to leakage.

A leak in the bellows, as discussed above, by definition, is not a large early release frequency (LERF) contributor. Rather a leak in this situation is a small, short-lived release that exists only as long as the containment pressure is above the system pressure. Thus, the potential for incremental bellows degradation resulting from the proposed increased time between the IRLTs would have a negligible impact on core damage probabilities or dose consequences.

NRC Question 4:

Inspections of some reinforced and steel containments have indicated degradation from the uninspectable (embedded) side of the drywall steel shell and steel liner of the primary containment. As noted in your license amendment, Surry 1 IWL inspection identified a 2-inch by 12-inch piece of wood in the dome of the containment. If a piece of wood is lodged near the liner of the containment cylinder or dome, it cannot be found by VT-3 or VT-1 IWE examinations unless the resulting liner degradation is through the thickness of the liner or 100% of the uninspectable surfaces are periodically examined by ultrasonic testing. The subatmospheric state of the containment cannot detect a through liner hole initiating for the uninspectable side of the liner, as the concrete is in compression during the operating condition. Please provide information as to how the potential leakage due to aging related degradation described above is factored into the risk assessment related to the extension of the integrated leak rate test.

Response:

Inspections of the containment liner are performed during the interval between ILRTs. The extension of the ILRT period will not affect the inspections. The following inspections are performed:

- The performance-based ILRT program guidance (NEI 94-01 and Regulatory Guide 1.163) requires a minimum of three inspections of the accessible portions of the inside and outside of the containment structure to assess the condition of the containment structure during the ten year interval. Engineering personnel perform these inspections. Any identified discrepancies noted in the liner, penetrations or concrete are documented and dispositioned in accordance with the appropriate Code/design requirements. These inspections are conducted using a mixture of direct and remote examination techniques.

- The accessible portions of the containment liner are inspected during each of the three periods in the ten-year inspection interval as required by ASME Code, Section IWE. These inspections are performed by qualified personnel, and any identified discrepancies are documented and dispositioned in accordance with ASME Section XI requirements. These inspections are conducted using a mixture of direct and remote examination techniques.

- Coating inspections are performed each outage on accessible portions of the containment liner by engineering personnel. Any identified discrepancies in the coating or liner are documented and dispositioned in accordance with the appropriate design standards.

These visual inspections of the containment have proven to be effective in identifying degradation of either the interior liner or the exterior concrete surface, as evidenced by the recent IWL inspection findings at Surry.

An undetected through-wall hole in both the concrete and the liner, at approximately the same location would have to be postulated to be a LERF contributor. Furthermore, both leak paths would have to exist long enough for the pathways to grow sufficiently such that the release would be large enough to be considered a LERF contributor. As a result of the liner and concrete inspections, the likelihood of an undetected through-wall path from the containment atmosphere to the environment for even a very small leak is considered to be remote. The likelihood of occurrence of an undetected through wall path becomes even smaller as the assumed leak size increases. A sensitivity analysis has been performed to estimate the impact of failure from a defect initiated between the containment wall and the liner. This sensitivity analysis used historical data to establish flaw likelihood. Given the assumed liner flaw, the containment fragility analysis is used to estimate the probability of breaching the containment at the design pressure. Finally, the likelihood of visual detection failure is assessed and included in the analysis. The product of these terms is the likelihood of non-detected containment leakage, which was calculated for both the containment cylinder and the basemat in the sensitivity analysis. The product of this likelihood and the non-large early release frequency is the increase in LERF due to non-detected containment leakage. The table below shows the key calculations and assumptions in the sensitivity analysis.

Surry Liner Corrosion Sensitivity Analysis

Step	Description	Containment Cylinder and Dome 85%	Containment Basemat 15%
1	**Historical Liner Flaw Likelihood** Failure Data: Containment location specific. Success Data: Based on 70 steel-lined Containments and 5.5 years since the 10 CFR 50.55a requirement for periodic visual inspections of containment surfaces.	Events: 2 (Brunswick 2 and North Anna 2) 2/(70 x 5.5) = **5.2E-3**	Events: 0 Assume half a failure 0.5/(70 x 5.5) = **1.3E-3**
2	**Aged Adjusted Liner Flaw Likelihood** During 15-year interval, assumed failure rate doubles every five years (14.9% increase per year). The average for 5th to 10th years was set to the historical failure rate.	**Year** / **Failure Rate** 1 / 2.1E-3 avg. 5-10 / 5.2E-3 15 / 1.4E-2 **15 year avg. = 6.27E-3**	**Year** / **Failure Rate** 1 / 5.0E-4 avg. 5-10 / 1.3E-3 15 / 3.5E-3 **15 year avg. = 1.57E-3**
3	**Increase in Flaw Likelihood Between 3 and 15 years** Uses aged adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every five years.	**8.7%**	**2.2%**
4	**Likelihood of Breach in Containment Given Liner Flaw** The upper end pressure is consistent with the Calvert Cliffs Probabilistic Risk Assessment (PRA) Level 2 analysis. 0.1% is assumed for the lower end. Intermediate failure likelihood is determined through logarithmic interpolation. The basemat is assumed to be 1/10 of the cylinder/dome analysis. The same value will be used for SPS as was used for CCNP since it was considered to be conservative based on Surry fragility curves.	Pressure (psia) / Likelihood of Breach 20 / 0.1% 64.7 (ILRT) / 1.1% 100 / 7.02% 120 / 20.3% 150 / 100%	Pressure (psia) / Likelihood of Breach 20 / 0.01% 64.7 (ILRT) / 0.11% 100 / 0.7% 120 / 2.0% 150 / 10.0%
5	**Visual Inspection Detection Failure Likelihood**	**10%**[1]	**100%** Cannot be visually inspected
6	**Likelihood of Non-Detected Containment Leakage (Steps 3*4*5)**	8.7% x 1.1% x 10%=**.0096%**	2.2% x 0.11% x 100%=**.0024%**
7	The total likelihood of the corrosion-induced, non-detected containment leakage is the sum of Step 6 for the containment cylinder and dome and the containment basemat.	0.0096% + 0.0024% =**0.012%**	
8	**The Non-Large Early Release Frequency (LERF)**[2]	**1.9E-5/yr**	
9	**Increase in LERF (ILRT 3/10 to 1/15 years)**	0.00012 x 1.9E-5 = **2.28E-9/year**	

[1]5% failure to identify visual flaws plus 5% likelihood that the flaw is not visible (not through-cylinder but could be detected by ILRT). To date all events have been detected through visual inspection. 5% visible failure detection is a conservative assumption.

[2]The non-large early release frequency (LERF) containment over-pressurization failures for SPS is estimated at 1.9E-5/yr. This is based on the total CDF minus the Class 1, 3B and 8 frequencies as calculated by (1.9E-5 = 3.78E-5 – (1.41E-5 + 7.94E-7 + 3.94E-6)). The total CDF is 3.78E-5/yr.

NRC Question 5

An alternate method to assess the change in risk in terms of Large Early Release Frequency (LERF) is to consider the total change in LERF from the baseline case to the proposed case. Please provide this assessment for Surry.

Response:

As requested, the alternative approach is presented. The baseline LERF is 7.94E-7/yr and for the proposed test extension to 1-in-15 year the LERF is 9.13E-7/yr. The change in LERF is:

$$\Delta\text{LERF} = 9.13\text{E-}7 - 7.94\text{E-}7 = 1.19\text{E-}7/\text{yr}.$$

The Surry containment integrity is inspected regularly. As discussed in the response to RAI number 4, the liner is inspected (IWE) and the exterior concrete is inspected (IWL) at about three year intervals. A coatings inspection is performed during each refueling outage. As a result, visual inspections insure containment integrity with a greater frequency than the baseline Type A test interval. Assuming these visual inspections in sum provide the same assurance of containment integrity as the Type A test there should be no increase in the LERF frequency due to the extended interval. However, a section of the liner is below the basemat and there are areas above the basemat that are obstructed. As a result, a percentage of the containment area could be subject to increased leakage due to the longer interval between Type A tests.

The inspected and non-inspected areas have been calculated using dimensions from plant drawings and the non-inspected area is approximately 15%. To account for additional containment liner surfaces that are not accessible inside containment the non-inspected surface area is rounded up to 20%. The effective change in LERF is calculated to be:

$$\Delta\text{LERF} = 0.20 \times (1.19\text{E-}7) = 2.38\text{E-}8/\text{yr}.$$

The change in LERF from the 3-in-10 year interval to the 1-in-15 year interval is below the Regulatory Guide 1.174 limit of 1E-7/yr.

Attachment

Request for Additional Information
Proposed Risk-Informed Technical Specifications Change
Five-Year Extension of Type A Test Interval

North Anna Power Station Unit 1
Virginia Electric and Power Company
(Dominion)

Since the inservice inspection requirements of 10 CFR 50.55a complement the leak rate testing requirements of Option B of Appendix J in ensuring the leak-tightness and structural integrity of the containment, the staff needs the following information:

NRC Question 1:

In formulating your IWE/IWL program for North Anna 1, you considered the first inspection period as five years (September 9, 1996 to September 8, 2001) – the period given to the licensees to complete their first period examinations in 10 CFR 50.55a. In the NRC response to NEI questions 13, 15 and 16 on containment inservice inspections requirements discussed in NRC letter to NEI entitled "Responses to NEI's Topic and Specific Issues Related to Containment Inspection Requirements," dated May 30,1997, the NRC explained that this interpretation of the rule was incorrect. The staff noted that the inspection periods should be determined as required in the ASME Code, Section XI. Please provide your actual start dates of the first and subsequent inspection periods for ASME Code Class CC and MC components in the first interval as required by the ASME Code, Section XI.

Response:

North Anna Unit 1 completed its first period IWE examinations on March 14, 2000, and its first interval IWL examinations by August 31, 2001. Using the NRC interpretation found in the reference provided by the NRC Staff, Letter to NEI from the NRC dated May 30, 1997, the North Anna Unit 1 IWE and IWL period and interval dates follow.

IWE 1st interval

- 1st period – March 15, 1997 to March 14, 2000
- 2nd period – March 15, 2000 to March 14, 2004
- 3rd period – March 15, 2004 to March 14, 2007

IWL 1st Interval

- September 1, 1996 to August 31, 2001 (five year interval for IWL)

Thus, the start of the second IWE interval will be March 15, 2007 and the start of the second IWL interval will be September 1, 2001.

NRC Question 2:

In the license application, you indicate that for the examination of seals and gaskets, and examination and testing of bolts associated with the primary containment pressure boundary (Examination Categories E-D and E-G), you had requested relief from the requirements of the Code. As an alternative, you plan to examine them during the leak rate testing of the primary containment. With the flexibility provided in Option B of Appendix J for Type B testing and Type C testing (as per NEI 94-01, and RG 1.163), and the extension requested in this amendment for Type A testing, please provide your schedule for examining and testing seals, gaskets, and bolting that assures the integrity of these components.

Response:

North Anna Unit 1 IWE Relief Request RR-IWE2 requested relief from the Section XI Code requirement to perform a visual VT-3 examination on seals and gaskets. The alternative accepted is as follows:

> "The leak-tightness of seals and gaskets will be tested in accordance with 10 CFR 50, Appendix J. The 10 CFR 50, Appendix J Type B testing is performed at least once each inspection interval."

North Anna Unit 1 performs some portion of the Appendix J Type B tests each refueling outage, staggering the testing to balance the outage work scope. Currently, these tests are completed in approximately 60-month intervals consistent with the Type C testing requirements. The current rule requires completion within 120 months. Thus, the current North Anna Unit 1 Type B testing frequency is more conservative.

The relief request basis states that Type B tests will continue to be completed within the 120-month interval and will adequately test the applicable seals and gaskets. The proposed one-time Appendix J, Type A extension will not affect this relief request basis.

North Anna Unit 1 IWE Relief Request RR-IWE5 requested relief from the Section XI Code requirement to perform bolt torque or tension tests on bolted connections not disassembled and reassembled during the inspection interval. The alternative accepted is as follows:

> "The following examinations and tests required by Subsection IWE ensure the structural integrity and leak-tightness of Class MC pressure retaining bolting, and therefore, no additional alternative examinations are proposed:
>
> (1) Exposed surfaces of bolted connections shall be visually examined in accordance with requirements of Table IWE-2500-1, Examination Category E-G, Pressure Retaining Bolting, Item No. E8.10, and
>
> (2) Bolted connections shall meet the pressure test requirements of Table IWE-2500-1, Examination Category E-P, All Pressure Retaining Components, Item E9.40."

The required visual examination frequency for Category E-G remains unaffected by the proposed Appendix J, Type A extension and will be completed as required by the Section XI Code (i.e., 100% in the inspection interval). Item E9.40 references the Appendix J, Type B test requirements, which are discussed above. Again, the Appendix J, Type A extension will not affect this relief request basis or the frequency of performing Type B testing on components with bolting.

NRC Question 3:

The stainless steel bellows have been found to be susceptible to trans-granular stress corrosion cracking, and the leakage through them are not readily detectable by Type B testing, as discussed in NRC Information Notice 92-20. Please provide information regarding inspection and testing of the bellows at North Anna 1 and how the potential bellows degradation has been factored into the risk assessment.

Response:

A stainless steel bellows is located inside containment on the outer tube of the fuel transfer tube containment penetration. The bellows inside containment on the outer pipe of the fuel transfer tube only compensates for any differential motion and does not form the containment boundary. The containment boundary is the welded connection at the containment liner to the inner and outer tubes and the double O-ring blank flange on the inner (fuel transfer) tube. The blank flange is Type B tested every refueling outage and the welded connection is tested during the integrated leak rate test (ILRT). A manual isolation valve isolates the inner (fuel transfer) tube from the spent fuel pool in the spent fuel building.

NRC Question 4:

Inspections of some reinforced and steel containments have indicated degradation from the uninspectable (embedded) side of the drywall steel shell and steel liner of the primary containment. As noted in your license amendment, North Anna 1 IWL inspection identified several pieces of wood in the concrete containment. If a piece of wood is lodged near the liner of the containment cylinder or dome, it cannot be found by VT-3 or VT-1 IWE examinations unless the resulting liner degradation is through the thickness of the liner or 100% of the uninspectable surfaces are periodically examined by ultrasonic testing. The subatmospheric state of the containment cannot detect a through liner hole initiating for the uninspectable side of the liner, as the concrete is in compression during the operating condition. Please provide information as to how the potential leakage due to aging related degradation described above is factored into the risk assessment related to the extension of the integrated leak rate test.

Response:

Inspections of the containment liner are performed during the interval between ILRTs. The extension of the ILRT period will not affect the inspections. The following inspections are performed:

- The performance-based ILRT program guidance (NEI 94-01 and Regulatory Guide 1.163) requires a minimum of three inspections of the accessible portions of the inside and outside of the containment structure to assess the condition of the containment structure during the ten year interval. Engineering personnel perform these inspections. Any identified discrepancies noted in the liner, penetrations or concrete are documented and dispositioned in accordance with the appropriate Code/design requirements. These inspections are conducted using a mixture of direct and remote examination techniques.

- The accessible portions of the containment liner are inspected during each of the three periods in the ten-year inspection interval as required by ASME Code, Section IWE. These inspections are performed by qualified personnel, and any identified discrepancies are documented and dispositioned in accordance with ASME Section XI requirements. These inspections are conducted using a mixture of direct and remote examination techniques.

- Coating inspections are performed each outage on accessible portions of the containment liner by engineering personnel. Any identified discrepancies in the coating or liner are documented and dispositioned in accordance with the appropriate design standards.

These visual inspections of the containment have proven to be effective in identifying degradation of either the interior liner or the exterior concrete surface, as evidenced by the recent IWL inspection findings at North Anna.

An undetected through-wall hole in both the concrete and the liner, at approximately the same location would have to be postulated to be a LERF contributor. Furthermore, both leak paths would have to exist long enough for the pathways to grow sufficiently such that the release would be large enough to be considered a LERF contributor. As a result of the liner and concrete inspections, the likelihood of an undetected through-wall path from the containment atmosphere to the environment for even a very small leak is considered to be remote. The likelihood of occurrence of an undetected through wall path becomes even smaller as the assumed leak size increases. A sensitivity analysis has been preformed to estimate the impact of failure from a defect initiated between the containment wall and the liner. This sensitivity analysis used historical data to establish flaw likelihood. Given the assumed liner flaw, the containment fragility analysis is used to estimate the probability of breaching the containment at the design pressure. Finally, the likelihood of visual detection failure is assessed and included in the analysis. The product of these terms is the likelihood of non-detected containment leakage, which was calculated for both the containment cylinder and the basemat in the sensitivity analysis. The product of this likelihood and the non-large early release frequency is the increase in LERF due to non-detected containment leakage. The table below shows the key calculations and assumptions in the sensitivity analysis.

North Anna Liner Corrosion Sensitivity Analysis

Step	Description	Containment Cylinder and Dome 85%	Containment Basemat 15%
1	**Historical Liner Flaw Likelihood** Failure Data: Containment location specific. Success Data: Based on 70 steel-lined Containments and 5.5 years since the 10 CFR 50.55a requirement for periodic visual inspections of containment surfaces.	Events: 2 (Brunswick 2 and North Anna 2) 2/(70 x 5.5) = **5.2E-3**	Events: 0 Assume half a failure 0.5/(70 x 5.5) = **1.3E-3**
2	**Aged Adjusted Liner Flaw Likelihood** During 15-year interval, assumed failure rate doubles every five years (14.9% increase per year). The average for 5^{th} to 10^{th} years was set to the historical failure rate.	Year / Failure Rate 1 / 2.1E-3 avg. 5-10 / 5.2E-3 15 / 1.4E-2 **15 year avg. = 6.27E-3**	Year / Failure Rate 1 / 5.0E-4 avg. 5-10 / 1.3E-3 15 / 3.5E-3 **15 year avg. = 1.57E-3**
3	**Increase in Flaw Likelihood Between 3 and 15 years** Uses age adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every five years.	**8.7%**	**2.2%**
4	**Likelihood of Breach in Containment Given Liner Flaw** The upper end pressure is consistent with the Calvert Cliffs Probabilistic Risk Assessment (PRA) Level 2 analysis. 0.1% is assumed for the lower end. Intermediate failure likelihood is determined through logarithmic interpolation. The basemat is assumed to be 1/10 of the cylinder/dome analysis. The same value will be used for NAPS as was used for CCNP since it is considered to be conservative based on SPS fragility curves.	Pressure (psia) / Likelihood of Breach 20 / 0.1% 64.7 (ILRT) / 1.1% 100 / 7.02% 120 / 20.3% 150 / 100.0%	Pressure (psia) / Likelihood of Breach 20 / 0.01% 64.7 (ILRT) / 0.11% 100 / 0.7% 120 / 2.0% 150 / 10.0%
5	**Visual Inspection Detection Failure Likelihood**	**10%**[1]	**100%** Cannot be visually inspected
6	**Likelihood of Non-Detected Containment Leakage (Steps 3*4*5)**	8.7% x 1.1% x 10% =**.0096%**	2.2% x 0.11% x 100% =**.0024%**
7	The total likelihood of the corrosion-induced, non-detected containment leakage is the sum of Step 6 for the containment cylinder and dome and the containment basemat.	0.0096%+ 0.0024% =**0.012%**	
8	**The Non-Large Early Release Frequency (LERF)**[2]	**1.38E-5/yr**	
9	**Increase in LERF (ILRT 3/10 to 1/15 years)**	0.00012 x 1.38E-5 = **1.66E-9/yr**	

[1]5% failure to identity visual flaws plus 5% likelihood that the flaw is not visible (not through-cylinder but could be detected by ILRT). To date all events have been detected through visual inspection. 5% visible failure detection is a conservative assumption.

[2]The non-large early release frequency (LERF) containment over-pressurization failures for NAPS is estimated at 1.38E-5/yr. This is based on the total CDF minus the Class 1, 3B and 8 frequencies as calculated by (1.38E-5 = 3.50E-5 – (1.46E-5 + 7.35E - 7+5.89E-6)). The total CDF is 3.50E-5/yr.

NRC Question 5:

An alternate method to assess the change in risk in terms of Large Early Release Frequency (LERF) is to consider the total change in LERF from the baseline case to the proposed case. Please provide this assessment for North Anna.

Response:

As requested, the alternative approach is presented. The baseline LERF is 7.35E-7/yr and for the proposed test extension to 1-in-15 year the LERF is 8.45E-7/yr. The change in LERF is:

ΔLERF = 8.45E-7 – 7.35E-7 = 1.10E-7/yr.

The North Anna containment integrity is inspected regularly. As discussed in the response to RAI number 4, the liner is inspected (IWE) and the exterior concrete is inspected (IWL) at about three year intervals. A coatings inspection is performed during each refueling outage. As a result, visual inspections insure containment integrity with a greater frequency than the baseline Type A test interval. Assuming these visual inspections in sum provide the same assurance of containment integrity as the Type A test there should be no increase in the LERF frequency due to the extended interval. However, a section of the liner is below the basemat and there are areas above the basemat that are obstructed. As a result, a percentage of the containment area could be subject to increase leakage due to the longer interval between Type A tests.

The inspected and non-inspected areas have been calculated using dimensions from plant drawings and the non-inspected area is about 15%. To account for additional containment liner surfaces that are not accessible inside containment the total non-inspected surface is rounded up to 20%. The effective change in LERF is calculated to be:

ΔLERF = 0.20 x (1.10E-7) = 2.20E-8/yr.

The delta LERF from the 3-in-10 year interval to the 1-in-15 year interval is below the Regulatory Guide 1.174 limit of 1E-7/yr.