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W3F1-2016-0074

December 7, 2016

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

SUBJECT: Responses to Request for Additional Information Set 5 Regarding the License Renewal Application for Waterford Steam Electric Station, Unit 3 (Waterford 3)
Docket No. 50-382
License No. NPF-38

REFERENCES:

1. Entergy letter W3F1-2016-0012 "License Renewal Application, Waterford Steam Electric Station, Unit 3" dated March 23, 2016.

2. NRC letter to Entergy "Requests for Additional Information for the Review of the Waterford Steam Electric Station, Unit 3, License Renewal Application – Set 5" dated November 7, 2016.

3. Entergy letter W3F1-2016-0063 "Responses to Request for Additional Information Set 1 Regarding the License Renewal Application for Waterford Steam Electric Station, Unit 3" dated October 13, 2016.

Dear Sir or Madam:

By letter dated March 23, 2016, Entergy Operations, Inc. (Entergy) submitted a license renewal application (Reference 1).

In letter dated November 7, 2016 (Reference 2), the NRC staff made a Request for Additional Information (RAI) Set 5, needed to complete its review. Enclosure 1 provides the responses to the Set 5 RAIs.

Also, Enclosure 2 contains a revision to the response to RAI B1.4-1 which was provided in Reference 3. The change to the License Renewal Application (LRA) Appendix B Section B.1.4 was inadvertently truncated from the response. Enclosure 2 contains the complete response to RAI B1.4-1.

There are no new regulatory commitments contained in this submittal. If you require additional information, please contact the Regulatory Assurance Manager, John Jarrell, at 504-739-6685.

I declare under penalty of perjury that the foregoing is true and correct. Executed on December 7, 2016.

Sincerely,

for MRC/AJH

Enclosures: 1. Set 5 RAI Responses – Waterford 3 License Renewal Application
2. RAI B1.4-1 Revised Response

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Enclosure 1 to

W3F1-2016-0074

Set 5 RAI Responses
Waterford 3 License Renewal Application

RAI 3.1.2-1

Background:

Table 3.1.2-4 of the LRA lists several carbon steel steam generator components externally exposed to indoor air with no aging affect or AMP identified. These AMR items cite generic note G and plant-specific note 105, which states that high component surface temperatures preclude moisture accumulation that could result in corrosion.

These carbon steel components are located in the containment air environment, which, as identified in other AMR items, is an environment of air with borated water leakage. Table 3.0-1 of the LRA shows that an air with borated water leakage environment is similar to the air-indoor uncontrolled environment. Table IX.D of the GALL Report describes the air-indoor uncontrolled environment as associated with systems with temperatures above the dew point where the surfaces of components may be wetted, but only rarely.

Issue:

During refueling outages, these components will be at ambient temperatures, which may or may not be above the dew point. Therefore, they may be susceptible to a condensation environment during outages. The GALL Report recommends that GALL Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” be used to manage loss of material due to general, pitting, and crevice corrosion for steel components exposed to uncontrolled indoor air.

Request:

Provide the technical basis or operating experience to justify why loss of material due to general, pitting, and crevice corrosion is not an applicable aging effect for the subject steam generator components, given that, during normal plant events such as refueling outages, particularly during prolonged outages, if any, these components will be at or near ambient temperatures. Alternatively, provide AMR items that describe how this aging effect will be managed.

Waterford 3 Response

Loss of material due to general, pitting, and crevice corrosion is not a significant aging effect for steel components of the steam generators with high operating temperatures (> 212 ^{0}F) that have external surfaces exposed to indoor air. During normal operation, these components are at temperatures where condensation is precluded. Without the presence of moisture from condensation, corrosion is not possible. During shutdown conditions such as refueling outages, these components are at or near ambient temperatures, which are maintained above the dew point. Condensation occurs when component temperatures are below the dew point. These conditions occur only briefly, if at all, during shutdown operations such that condensation is not expected on steam generator external surfaces. Operating experience supports the conclusion that these components do not exhibit loss of material due to corrosion. For example, the exterior surfaces of the original steam generators showed no significant corrosion when the generators were removed in 2012 after approximately 30 years of service.

RAI 3.3.2.3.4-1

Background

LRA Table 3.3.2-4 states that for plastic regulator bodies and filter bodies exposed to condensation (internal) and indoor air (external) there is no aging effect and no AMP is proposed. The AMR item cites generic note F.

Issue:

During the audit the staff interviewed the applicant. The applicant stated that it could not determine the components' plastic material type. They also stated that the components are located in the main control room and are portions of the compressed air system interface with the breathing air system. The staff noted that plastics in general are susceptible to degradation due to exposure to environmental factors such as temperature, radiation, ozone, sunlight, oxidation, and ultraviolet light (GALL Report Chapter IX.E, "Use of Terms for Aging").

Request:

Confirm the portion of the air system in which the regulators and filters are installed and the location of the components.

State the basis for why environmental factors including temperature, radiation, ozone, sunlight, oxidation, and ultraviolet light will not cause degradation of the components.

Waterford 3 Response

Regulator bodies and filter housings included in LRA Table 3.3.2-4 are installed in seven locations within the control room environment as a part of packaged units for the distribution of emergency breathing air. The units are located in a controlled environment and are not subject to abnormal conditions, but they are exposed to florescent light. Different types of plastics are less susceptible to degradation than others when exposed to the ambient conditions of the control room environment. With uncertainty of the plastic material type, an aging effect of "change in material properties" is conservatively applied to the filter housings and regulator bodies.

The LRA is revised as follows. Additions are shown with underline and deletions with strikethrough.

3.3.2.1.4 Compressed Air

Aging Effects Requiring Management

The following aging effects associated with the compressed air system require management.

- <u>Change in material properties</u>
- Cracking
- Loss of material
- Loss of material – wear
- Loss of preload

Table 3.3.2-4
Compressed Air System
Summary of Aging Management Evaluation

Table 3.3.2-4: Compressed Air System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG -1801 Item**	**Table 1 Item**	**Notes**
Filter housing	Pressure boundary	Plastic	Air – indoor (ext)	~~None~~ Change in material properties	~~None~~ External Surfaces Monitoring	--	--	F
Regulator body	Pressure boundary	Plastic	Air – indoor (ext)	~~None~~ Change in material properties	~~None~~ External Surfaces Monitoring	--	--	F

RAI 4.2.3-1

Waterford 3 Response

Response to RAI 4.2.3-1 to accompany SET 6 RAI 4.7.4-1 response expected to be submitted in early February 2017 as discussed in email from P. Clark (NRC) to A. Harris (Entergy) dated 11/21/2016.

RAI 3.1.2.2.6.2-1

Background:

SRP-LR Section 3.1.2.2.6.2 recommends further evaluation to manage cracking due to stress corrosion cracking (SCC) in Class 1 PWR cast austenitic stainless steel (CASS) reactor coolant system piping, piping components, and piping elements exposed to reactor coolant. The SRP-LR indicates that SCC could occur in CASS components that do not meet the NUREG-0313, Revision 2, guidelines for ferrite and carbon content.

LRA Section 3.1.2.2.6.2 states that cracking due to SCC in these components will be managed by the Water Chemistry Control – Primary and Secondary and Inservice Inspection Programs. The LRA states that the Inservice Inspection Program provides qualified inspection techniques to monitor cracking.

Issue:

The applicant did not provide its methodology that will be used to identify CASS Class 1 reactor coolant system piping, piping components, and piping elements that do not meet the NUREG-0313 guidelines for ferrite and carbon content. In addition, the applicant did not provide enough information about the "qualified inspection techniques" within the Inservice Inspection Program that will monitor cracking.

Request:

1. Provide and justify the methodology used to identify CASS Class 1 reactor coolant system piping, piping components, and piping elements that do not meet the NUREG-0313 guidelines for ferrite and carbon content.

2. Provide the inspection methodology, including inspection technique and frequency that will be used to detect and monitor cracking of these components. Justify that this inspection methodology will be adequate to detect and monitor cracking due to SCC during the period of extended operation.

Waterford 3 Response

1. For potentially susceptible in-scope cast austenitic stainless steel (CASS) components, the certified material test reports will be reviewed to determine if they meet the NUREG-0313 guidelines for ferrite and carbon content.

2. Neither enhanced visual examination nor any other inspection technique is qualified by ASME or EPRI for the detection of cracking due to SCC in ASME Class 1 CASS piping components. Consequently, Entergy will work with ASME and EPRI to identify a viable inspection method for the detection of cracking in ASME Class 1 CASS piping. When developed, the inspections will be implemented under the Inservice Inspection Program as supplemental inspections, which will be performed on a sampling basis. The extent and frequency of sampling will be based on the established method of inspection and industry operating experience and practices when the program is implemented, and will include components deemed limiting from a standpoint of applied stress, operating time, and environmental considerations.

To clarify the LRA based on the above discussion, changes to LRA sections 3.1.2.2.6, Item 2; A.1.15; A.4 and B.1.15 follow with additions underlined and deletions lined through.

LRA Section 3.1.2.2.6

Cracking due to SCC of cast austenitic stainless steel (CASS) Class 1 piping, piping components, and piping elements exposed to reactor coolant will be managed by the Water Chemistry Control – Primary and Secondary and Inservice Inspection Programs. The Water Chemistry Control – Primary and Secondary Program minimizes contaminants that ~~which~~ promote SCC. ~~The Inservice Inspection Program provides qualified inspection techniques to monitor cracking.~~ For CASS components that do not meet the NUREG-0313 guidelines with regard to ferrite and carbon content, inspection techniques qualified by ASME or EPRI will be used as part of the Inservice Inspection Program to manage cracking.

Susceptibility to thermal aging embrittlement will be evaluated in the Thermal Aging Embrittlement of CASS Program. Aging management for components that are determined to be susceptible to thermal aging embrittlement is accomplished using either enhanced visual examinations or component-specific flaw tolerance evaluations. Additional inspection or evaluations are not required for components that are determined not to be susceptible to thermal aging embrittlement.

LRA Section A.1.15 Inservice Inspection Program

- Revise Inservice Inspection Program procedures to include a supplemental inspection of Class 1 CASS piping components that do not meet the material selection criteria of NUREG-0313, Revision 2, with regard to ferrite and carbon content. An inspection technique qualified by ASME or EPRI will be used to monitor cracking.

LRA Section A.4

12.a	Inservice Inspection Program	Revise Inservice Inspection Program procedures to include a supplemental inspection of Class 1 CASS piping components that do not meet the material selection criteria of NUREG-0313, Revision 2, with regard to ferrite and carbon content. An inspection technique qualified by ASME or EPRI will be used to monitor cracking.	Prior to June 18, 2024	W3F1-2016-0074

LRA Section B.1.15 INSERVICE INSPECTION

Enhancements
~~None~~

Element Affected	Enhancement
4. Detection of Aging Effect	Revise Inservice Inspection Program procedures to include a supplemental inspection of Class 1 CASS piping components that do not meet the material selection criteria of NUREG-0313, Revision 2, with regard to ferrite and carbon content. An inspection technique qualified by ASME or EPRI will be used to monitor cracking.

RAI B.1.31-1

Background:

The “scope of program” program element of the license renewal application (LRA) Aging Management Program (AMP) states that the Protective Coating Monitoring and Maintenance Program manages the effects of aging on Service Level I coatings applied to external surfaces of carbon steel and concrete inside containment. The Generic Aging Lessons Learned (GALL) Report AMP recommends that the minimum scope of the program include Service Level I coatings applied to steel and concrete surfaces inside containment to minimize degradation of coatings that can lead to clogging of Emergency Core Cooling Systems suction strainers. This ensures operability of post-accident safety systems that rely on water recycled through the containment sump/drain system.

Issue:

It is not clear to the staff that the scope of the LRA AMP is consistent with the scope of the NUREG-1801 Protective Coating Monitoring and Maintenance Program since the licensee’s inspection program documents do not specify the surfaces to be inspected. In addition, in response to Generic Letter 2004-02 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML080650615), the licensee described indeterminate coatings, and indicated that all failed coatings are assumed to transport completely to the sump. Therefore, it is not clear to the staff how failed coatings are addressed in the licensee’s inspection program to effectively manage coatings inside containment.

Request:

Please describe the coatings that are included within the scope of inspections consistent with your LRA AMP. Your description should include a discussion of how inspection findings are used to quantify degraded coatings, unqualified coatings, and indeterminate coatings for comparison to assumptions in sump screen performance analyses. Finally, you should also describe how available margins are adequate to allow for further coating degradation prior to the next inspection.

Waterford 3 Response

As described in Waterford 3 (WF3) license renewal application (LRA) Section B.1.31, the Protective Coating Monitoring and Maintenance Program manages the aging effects of Service Level I coatings applied to external surface of components inside the steel containment vessel (SCV).

Coatings are classified as qualified or unqualified. Indeterminate coatings are treated as unqualified coatings. Qualified coatings are defined as a coating system used inside the reactor containment building that can be attested to having passed the required laboratory testing, including irradiation and simulated design basis accident (DBA) and has adequate quality documentation to support its use as DBA qualified. The qualified coatings, if in good condition, will become debris only within the zone of influence (ZOI). All unqualified coatings and damaged qualified coatings are presumed to become debris during a loss of coolant accident (LOCA), even when outside the ZOI.

A sample of qualified containment coatings are inspected every refueling outage in accordance with Waterford 3 site procedures to ensure the coatings are maintained in good condition and that degraded conditions are evaluated, quantified, and tracked. Containment coatings included within the inspections

under this program are coatings with potential problems, degraded areas identified on records of previous inspections, coatings on concrete and steel surfaces inside the safety injection sump (SIS), and approximately 10% of the remaining coated surfaces inside primary containment, excluding concrete and insulated piping. Coatings that are identified as degraded or failed are documented on inspection sheets, tracked and evaluated through the corrective action program. Degraded coatings are quantified in terms of area and then multiplied by conservative coating thickness values for comparison to the debris volume assumptions in sump screen performance analyses.

Entergy maintains a log of indeterminate and unqualified coatings in a calculation. The total volume of indeterminate and unqualified coatings is included in the total debris generation calculation as contributing to blockage of the SIS. Margin to account for additional degradation of qualified coatings exists in that degraded coating area is approximately one-third of the area of degraded qualified coatings assumed in the calculation. A conservative assumption in the “coating debris” calculation is that all indeterminate and unqualified coatings are considered to become debris during a LOCA, even when outside the ZOI. As part of the corrective action process, the amounts of degraded or failed qualified coatings that are identified during the inspections are compared to the assumed amount of degraded qualified coatings in the site calculation for “Debris Generation Due To LOCA within Containment for Resolution of GSI-191”. Waterford 3 operating experience indicates that coating degradation has not significantly impacted available margins. Inspections performed between 2006 and 2014 show that the amount of degraded coatings identified was on average 32 square feet per refueling cycle. This average is based on an initial finding in 2006 of 1336 square feet of degraded coating. When compared to the amount of allowable unqualified coating, approximately 4226 square feet, this indicates that significant margin remains available. Continuation of these proven inspection methods will ensure that coating degradation is identified and evaluated and that adequate margin is maintained to allow for additional coating degradation prior to the next inspection.

RAI B.1.31-2

Background:

During an audit conducted during the week of July 11, 2016, the licensee provided information to the staff regarding coating degradation found in containment. The failed coating system was Carboline Carbo Zinc 11 (CZ11) primer top coated with Carboline Phenoline 305. The licensee stated that the failure mechanism was splitting of CZ11 primer leaving only CZ11 primer on the substrate; however, a formal root cause evaluation had not been performed or was not readily available.

Issue:

It is not clear to the staff that the operating experience for the licensee's Service Level I coatings is consistent with industry operating experience since a root cause evaluation was not performed to determine the reason for the splitting of the CZ11 primer.

Request:

Please describe actions taken to determine the root cause of CZ11 primer degradation in containment, including means for ensuring that coatings currently categorized as qualified are not susceptible to the same failure mechanism.

Waterford 3 Response

The coating degradation discussed during the July 2016 audit was most recently observed in 2015 containment coating inspections. The degradation was typical of what had been observed during previous inspections. Therefore, no formal root cause evaluation was performed.

The cause of the splitting of the carbo-zinc 11 (CZ-11) primer is believed related to coatings issues inside the SCV that date back to Waterford 3 (WF3) original construction. Coating degradation issues were documented as a significant construction deficiency and addressed in Waterford 3 nonconformance reports. Potential causes of the coating problems were identified (e.g., a mist layer of coating being applied too thick resulting in globules, poor primer batches, and improper QA requirements imposed on coating application). Corrective actions included repair, recoat, and additional inspections and testing (including adhesion testing, dry film thickness measurements and in-situ design basis accident testing) to assess whether the major portion of the coating on the liner plate was acceptable. The assessment concluded that the degraded coating would not impact the Waterford 3 safety injection sump operation. However, the assessment could not rule out the potential for isolated areas of future coating degradation. As part of the resolution to the coating issue inside the SCV, Waterford 3 committed to inspect containment coatings every refueling outage. This commitment continues, ensuring coating degradation (including delamination) will not exceed the extent of degradation assumed in the safety injection sump performance calculation. Corrective actions including repair, recoating, or removal of degraded coating are taken as necessary.

RAI B.1.31-3

Background:

The "acceptance criteria" program element of the LRA AMP states that the Protective Coating Monitoring and Maintenance Program meets the technical basis of American Society for Testing and Materials (ASTM) D 5163-08 and provides an effective method to assess coating condition through visual inspections. The GALL Report AMP recommends additional ASTM and other recognized test methods, in addition to visual inspections, for use in characterizing the severity of observed coating defects and deficiencies.

Issue:

It is not clear to the staff that these LRA AMP statements are consistent with implementation since it appears that the licensee has not performed additional tests (e.g., adhesion tests) to properly bound degradation of Service Level I Coatings that are present in the containment building.

Request:

Significant quantities of degraded coatings have been identified by the licensee through visual assessment. Specifically, condition reports reviewed by the staff during the audit (CR-WF3-2005-02046, CR-WF3-2011-02987, and CR-WF3-2015-08489) showed that additional quantities of degraded coatings are identified through inspections each outage. Given the apparent active degradation of the coatings, please describe actions taken to determine the extent of condition, including any physical testing that has been performed, or is planned, in order to determine if the degradation extends beyond that identified by visual assessment.

Waterford 3 Response

As provided in the Waterford 3 (WF3) response to RAI B.1.31-2, the cause determination of coating degradation inside the steel containment vessel (SCV) dates back to the time of plant construction. Degraded coating conditions were thoroughly evaluated and documented at that time. Evaluations included determination of corrective actions that have been incorporated into plant procedures since Waterford 3 plant startup. The diagnostic actions beyond visual assessment included dry film thickness measurements, adhesion testing and in-situ design basis accident testing performed to determine the cause and the extent of the degraded coating. Waterford 3 considers the coating degradation identified in the condition reports identified in this RAI request as an ongoing continuation of previously identified coating degradation. Because the degradation is typical of previous degradation related to coating issues evaluated during plant construction, no additional testing of these degraded coatings is planned.
As discussed in the response to RAI B.1.31-1, margin to account for additional degradation of qualified coatings exists in that the identified degraded coating area is approximately 38 percent of the area of degraded qualified coatings assumed in the safety injection sump performance calculation. Based on inspections performed from 2006 to 2015, the running total of degraded coating area has ranged from 1,336 square feet in 2006 to 1,621 square feet in 2015. The total has increased by 285 square feet or approximately 21 percent over six Waterford 3 operating cycles. The majority of containment coating failures observed were not new, but had been observed and documented during previous inspections. Furthermore, failed coatings can be replaced or completely removed to reduce the running total if necessary to ensure that adequate margin is maintained. Based on the allowable 4,226 square feet of degraded qualified coating, significant margin remains available to account for degradation beyond that identified in the visual assessments.

RAI 3.2.2.2-1

Background:

Section 54.21(a)(3) of 10 CFR requires the applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function will be maintained consistent with the current licensing basis for the period of extended operation. As described in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," and when evaluation of the matter in the GALL Report applies to the plant.

The LRA states that the Water Chemistry Control-Primary and Secondary program will be consistent with GALL Report AMP XI.M2, "Water Chemistry." GALL Report AMP XI.M2 recommends a verification of the effectiveness of the chemistry control program, such as GALL Report AMP XI.M32, "One-Time Inspection," to ensure that significant degradation is not occurring and the component's intended function is maintained during the period of extended operation.

Issue:

LRA Table 3.2.2-2 states that the nickel alloy thermowell exposed to treated borated water will be managed by the Water Chemistry Control-Primary and Secondary program for loss of material. The line item in question does not have a plant-specific note indicating that it will be included in the One-Time Inspection program inspection sample, as recommended by
GALL Report AMP XI.M2.

Request:

Confirm that a one-time inspection program such as GALL Report, AMP XI.M32, "One-Time Inspection," will be used to verify the effectiveness of the Water Chemistry Control-Primary and Secondary program for managing loss of material by including the nickel alloy thermowell in the One-Time Inspection program or provide the bases for not including the item in question in the One-Time Inspection program.

Waterford 3 Response

The One-Time Inspection program will verify the effectiveness of the Water Chemistry Control – Primary and Secondary Program for managing loss of material. The description of the Water Chemistry Control – Primary and Secondary Program in Appendix B, Section B.1.41, states that the One-Time Inspection Program as described in Section B.1.28 includes inspections to verify that the Water Chemistry Control – Primary and Secondary Program has been effective at managing the effects of aging. The description of the One-Time Inspection Program includes the aging effect of loss of material for the Water Chemistry Control – Primary and Secondary Program.

The plant-specific note for using the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Control – Primary and Secondary Program (Note 201) is not used in the Waterford 3 license renewal application for line items that do not have a matching NUREG-1801 line item (no table entries in columns "NUREG-1801 Item" and "Table 1 Item"). Plant-specific notes are used to help explain how a program compares to the NUREG-1801 program for that line item and therefore have no purpose for line items that are not compared to NUREG-1801.

RAI 3.3.2.7-1

Background:

Section 54.21(a)(3) of 10 CFR requires the applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function will be maintained consistent with the current licensing basis for the period of extended operation. As described in the Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL Report and when evaluation of the matter in the GALL Report applies to the plant.

Element 4 of GALL Report AMP XI.M30, "Fuel Oil Chemistry," states that, "Prior to the period of extended operation, a one-time inspection (i.e., AMP XI.M32) of selected components exposed to diesel fuel oil is performed to verify the effectiveness of the Fuel Oil Chemistry program."

Issue:

The LRA states that the Diesel Fuel Monitoring program will be consistent with the program described in NUREG-1801, Section XI.M30, Fuel Oil Chemistry. LRA Table 3.3.2-7 includes stainless steel heat exchanger tubes exposed to fuel oil that will be managed by the Diesel Fuel Monitoring program for reduction of heat transfer. However, GALL Report AMP XI.M30 only manages loss of material and does not include reduction of heat transfer; it is unclear how the Diesel Fuel Monitoring program will be effective in managing the reduction of heat transfer.

Additionally, the staff notes that other aging effects are being verified by GALL Report, AMP XI.M32, "One-Time Inspection," as indicated by a plant-specific note in the aging management review results tables. The line item in question does not include the plant-specific note for using the One-Time Inspection program to verify effectiveness of the Diesel Fuel Monitoring program. It is unclear whether the effectiveness of the program will be verified for reduction of heat transfer.

Request:

1. Provide the technical bases to demonstrate that reduction of heat transfer for the heat exchanger tubes in question will be adequately managed by the Diesel Fuel Monitoring program.

2. Confirm that the One-Time Inspection program will verify the effectiveness of the Diesel Fuel Monitoring program for managing reduction of heat transfer or provide the bases for not needing this verification.

Waterford 3 Response

1. As stated in NUREG-1801, Section XI.M30, the Fuel Oil Chemistry Program manages fouling that causes corrosion. The aging mechanism for reduction of heat transfer is also fouling. As described in LRA Appendix B, Section B.1.8, the Diesel Fuel Monitoring Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.M30. Therefore, the Diesel Fuel Monitoring Program activities that manage fouling also manage the aging effect of reduction of heat transfer.

2. The One-Time Inspection program will verify the effectiveness of the Diesel Fuel Monitoring Program for managing reduction of heat transfer. The description of the Diesel Fuel Monitoring Program in Appendix B, Section B.1.8, states that the One-Time Inspection Program as described in Section B.1.28 includes inspections to verify that the Diesel Fuel Monitoring Program has been effective at managing the effects of aging. The description of the One-Time Inspection includes the aging effect of reduction of heat transfer for the Diesel Fuel Monitoring Program.

   The plant-specific note for using the One-Time Inspection Program to verify the effectiveness of the Diesel Fuel Monitoring Program (Note 303) is not used in the Waterford 3 license renewal application for line items that do not have a matching NUREG-1801 line item (no table entries in columns "NUREG-1801 Item" and "Table 1 Item"). Plant-specific notes are used to help explain how a program compares to the NUREG-1801 program for that line item and, therefore, are unnecessary for line items that are not compared to NUREG-1801.

Enclosure 2 to

W3F1-2016-0074

RAI B1.4-1 Revised Response
Waterford 3 License Renewal Application

<u>RAI B1.4-1 Revised Response</u>

The program description of the Coating Integrity Program, and its associated FSAR Supplement, state that coatings that are within the scope of the program are those that are applied to the internal surfaces of in-scope components where loss of coating or lining integrity could impact the component's <u>and</u> downstream component's current licensing basis intended function(s).

<u>Issue:</u>

GALL Report AMP XI.M42, "Internal Coatings/Linings for In-scope Piping, Piping Components, Heat Exchangers, and Tanks," recommends that coatings are within the scope of the AMP where loss of coating or lining integrity could prevent satisfactory accomplishment of any of the component's <u>or</u> downstream component's current licensing basis intended functions identified under 10 CFR 54.4(a)(1), (a)(2), or (a)(3). The scope of the Coating Integrity program is not consistent with the "scope of program" program element of AMP XI.M42 because the term "and" implies that both the component's intended function <u>and</u> a downstream component's intended function must be impacted by loss of coating integrity for the coating to be within the scope of the program. AMP XI.M42 recommends that the criteria for inclusion are either of the impacts.

<u>Request:</u>

State the basis for using the term "and" in the Coating Integrity Program description or revise the term to "or" in LRA Section B.1.4 and LRA Section A.1.4 to clarify which coatings are within the scope of the program.

<u>Waterford 3 Response</u>

The program description of the Coating Integrity Program as described in LRA Section B.1.4, and its associated FSAR Supplement as described in LRA Section A.1.4 are revised to state that coatings that are within the scope of the program are those that are applied to the internal surfaces of in-scope components where loss of coating or lining integrity could impact the component's or downstream component's current licensing basis intended function(s).

LRA Section A.1.4 is revised as follows. Additions are shown with underline and deletions with strikethrough.

A.1.4 <u>Coating Integrity Program</u>

The Coating Integrity Program consists of periodic visual inspections of coatings applied to the internal surfaces of in-scope components in an environment of raw water, treated water, lubricating oil, or fuel oil where loss of coating or lining integrity could impact the component's ~~and~~<u>or</u> downstream component's current licensing basis intended function(s). For coated surfaces that do not meet the acceptance criteria, physical testing is performed where physically possible in conjunction with coating repair or replacement. The training and qualification of individuals involved in coating inspections of noncementitious coatings are conducted in accordance with ASTM standards endorsed in Regulatory Guide (RG) 1.54 including limitations, if any, identified in RG 1.54 on a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces.

This program will be implemented prior to the period of extended operation.

LRA Section B.1.4 is revised as follows. Additions are shown with underline and deletions with strikethrough.

B.1.4 Coating Integrity Program

The Coating Integrity Program is a new program that will consist of periodic visual inspections of coatings applied to the internal surfaces of in-scope components in an environment of raw water, treated water, lubricating oil, or fuel oil where loss of coating or lining integrity could impact the component's ~~and~~or downstream component's current licensing basis intended function(s). For coated surfaces that do not meet the acceptance criteria, physical testing is performed where physically possible in conjunction with coating repair or replacement. The training and qualification of individuals involved in coating inspections of noncementitious coatings are conducted in accordance with ASTM standards endorsed in Regulatory Guide (RG) 1.54 including limitations, if any, identified in RG 1.54 on a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces.

This program will be implemented prior to the period of extended operation.