Proprietary Information - Withhold From Public Disclosure Under 10 CFR 2.390
The balance of this letter may be considered non-proprietary upon removal of Enclosure 3.

Entergy

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William F. Maguire
Site Vice President
River Bend Station

RBG-47861

May 29, 2018

Attn: Document Control Desk
U.S. Nuclear Regulatory Commission
11555 Rockville Pike
Rockville, MD 20852-2738

SUBJECT: Response to License Renewal Application NRC Request for Additional Information Sets 14,15 and Operating Experience Review Clarification, River Bend Station, Unit 1
Docket No. 50-458
License No. NPF-47

References:
1) Entergy Letter: License Renewal Application (RBG-47735 dated May 25, 2017)

2) NRC email: River Bend Station, Unit 1, Request for Additional Information, Set 14 – RBS License Renewal Application – dated April 30, 2018 (ADAMS Accession No. ML18121A029)

3) NRC email: River Bend Station, Unit 1, Request for Additional Information, Set 15 – RBS License Renewal Application – dated May 3, 2018 (ADAMS Accession No. ML18124A009)

4) NRC Teleconference: River Bend Station, Unit1, Operating Experience Review Clarification – May 21, 2018 (ADAMS Accession No. ML18143B686)

Dear Sir or Madam:

In Reference 1, Entergy Operations, Inc (Entergy) submitted an application for renewal of the operating license for River Bend Station (RBS) for an additional 20 years beyond the current expiration date. In an email dated April 30, 2018, (Reference 2) the NRC staff made a Request for Additional Information (RAI) needed to complete the license renewal application review. In an email dated May, 3, 2018 (Reference 3), the NRC Staff transmitted a revised version of RAI 3.6.2.2.2-1a regarding high-voltage insulators, which had been originally issued in Reference 2. In Reference 4, Entergy agreed to provide additional information to clarify the operating experience review process. Enclosure 1 contains the responses to RAI Sets 14,15, and operating experience review process. Enclosure 2 identifies a change to one commitment.

Enclosure 3 contains information that is considered proprietary; therefore, Enclosure 3 is requested to be withheld from disclosure to the public under 10 CFR 2.390. An affidavit from GE-Hitachi Nuclear Energy Americas LLC supporting withholding under 10 CFR 2.390 is included in Enclosure 3.

If you require additional information, please contact Mr. Tim Schenk at (225)-381-4177 or tschenk@entergy.com.

In accordance with 10 CFR 50.91(b)(1), Entergy is notifying the State of Louisiana and the State of Texas by transmitting a copy of this letter to the designated State Official.

I declare under penalty of perjury that the foregoing is true and correct. Executed on May 29, 2018.

Sincerely,

WFM/RMC/dp

Enclosure 1: Responses to RAI Sets 14,15 and Operating Experience Review Clarification – River Bend Station
Enclosure 2: Commitment – River Bend Station
Enclosure 3: Proprietary Information for Response to RAI 4.7.3-1 — River Bend Station

cc: (with Enclosure)

U. S. Nuclear Regulatory Commission
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cc: (w/o Enclosure)

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RBF1-18-0094

RBG-47861

Enclosure 1

Responses to Request for Additional Information

Sets 14, 15 and Operating Experience Review Clarification

REQUEST FOR ADDITIONAL INFORMATION
LICENSE RENEWAL APPLICATION
RIVER BEND STATION, UNIT 1 – SETS 14, 15 and Operating Experience Review Clarification
DOCKET NO.: 50-458
CAC NO.: MF9757
Office of Nuclear Reactor Regulation
Division of Materials and License Renewal

Question

RAI 4.3.1-2a (Class 1 Fatigue)

(Reference: RAI Set 10, ML18043A008 and ML18087A188)

Background

By letter dated March 26, 2018 (ADAMS ML18087A188), Entergy Operations Inc. (Entergy, or the applicant) submitted it response to RAI 4.3.1-1. In this response, the applicant identified the specific reactor vessel internal (RVI) components that were analyzed with a time-dependent cumulative usage factor (CUF) analysis in the current licensing basis (CLB) and provided the specific EPRI BWRVIP inspection and evaluation (I&E) reports that applied to the components.

Issue

The staff has been able to verify that the collective set of BWRVIP I&E reports referenced in the RAI response include inspection of all RVI component or component assemblies with CUF analyses in the CLB, with the exception of the core plate and core plate stiffener beams in the RVI design. Specifically, the EPRI I&E methodology in BWRVIP-25 does not include inspections of BWR-6 designed core plate assembly components because the core plate assemblies in these types of BWRs rely on structural wedges for maintaining the core plates in place during postulated design basis loading conditions and events. As a result, the applicant's use of BWRVIP-25 does not demonstrate that fatigue of core plate and core plate stiffener beams will be adequately managed during the period of extended operation in accordance with 10 CFR 54.21c(1)(iii).

Request

Justify that BWRVIP-25 is appropriate and adequate to manage fatigue of the core plate and core plate stiffener beams even though this document does not include inspections of these components.

Otherwise, provide an alternative program or alternate basis for dispositioning the CUF analyses of the core plate and core plate stiffener beams. Justify the basis selected to disposition the CUF analyses of the components in accordance with 10 CFR 54.21c(1)(i), (ii) or (iii).

Response

Fatigue, structural analysis, industry operating experience, and safety consequences were evaluated in BWRVIP-25 before concluding that inspections of the core plate and the core plate stiffener beam are not necessary. An alternate basis for evaluating the CUF analyses of the core plate and core plate stiffener beams is provided. A review of the fatigue calculation determined the usage factors for the core plate and stiffener beams would remain below 1 with the cycles projected for 60 years as identified in LRA Table 4.3-1. The counting of cycles performed under the Fatigue Monitoring Program will ensure these usage factors remain below 1. Therefore, the effects of aging due to fatigue of the core plate and stiffener beams are managed in accordance with 10 CFR 54.21(c)(1)(iii).

Changes to LRA Sections 4.3.1.2 and A.2.2.1 follow with additions underlined and deletions lined through.

4.3.1.2 Reactor Pressure Vessel Internals

The BWR Vessel Internals Program manages aging effects, including cracking due to fatigue for the reactor vessel internals. The program performs inspections and flaw evaluations in accordance with the guidelines of applicable BWRVIP reports. This program manages the aging effects of cracking, loss of preload, loss of material, and reduction in fracture toughness for BWR vessel internal components in a reactor coolant environment.

BWRVIP guidance does not specify inspection of the core plate and core plate stiffener beams. A review of the associated fatigue calculation determined the usage factors for the core plate and stiffener beams would remain below 1 with the cycles identified in LRA Table 4.3-1 projected for 60 years of operation. The counting of cycles under the Fatigue Monitoring Program will ensure these usage factors remain below 1. Therefore, the effects of aging due to fatigue of the core plate and stiffener beams are managed in accordance with 10 CFR 54.21(c)(1)(iii).

For other reactor vessel internals components with fatigue TLAAs, the effects of aging due to fatigue will be managed by the BWR Vessel Internals Program for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). For further information, see Section B.1.10, BWR Vessel Internals Program.

LRA Section A.2.2.1

Reactor Pressure Vessel Internals

For reactor vessel internals components with fatigue TLAAs, the effects of aging due to fatigue will be managed by the BWR Vessel Internals Program (Section A.1.10) for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). The program performs inspections and flaw evaluations in accordance with the guidelines of applicable BWRVIP reports. This program manages the aging effects of cracking, loss of preload, loss of material, and reduction in fracture toughness for BWR vessel internal components in a reactor coolant environment.

BWRVIP guidance does not specify inspection of the core plate and core plate stiffener beams. A review of the associated fatigue calculation determined the usage factors for the core plate and stiffener beams would remain below 1 with the cycles projected for 60 years of operation. The counting of cycles under the Fatigue Monitoring Program (Section A.1.18) will ensure these usage factors remain below 1. Therefore, the Fatigue Monitoring Program will manage the effects of aging due to fatigue of the core plate and stiffener beams in accordance with 10 CFR 54.21(c)(1)(iii).

Question

RAI 4.7.3-1a (Fluence Effects for Reactor Vessel Internals) **NON-PROPRIETARY**
(References: RAI Set 10, ML18043A008 and ML18087A188)

Background

SRP-LR Section 4.7.3.1.2 states that for a TLAA disposition pursuant to 10 CFR 54.21(c)(1)(ii), the applicant shall provide a sufficient description of the analysis and document the results of the reanalysis to show that it is satisfactory for the 60-year period.

By letter dated March 26, 2018 (ADAMS ML18087A188), applicant submitted its responses to numerous RAIs (including 4.7.3-1 and 4.7.3-2). In its responses to RAI 4.7.3-2 and part 4 of RAI 4.7.3-1, the applicant provided a summary of the fluence projections for the various core support structure (CSS) components. The applicant stated that components that were projected to remain within the fluence thresholds do not require consideration beyond meeting the American Society of Mechanical Engineers Code requirements.

Additionally, the applicant indicated that the neutron fluence values for several of the CSS components have been projected to exceed the fluence criteria, and that these components must be evaluated to determine whether they meet the additional criteria that are required to be assessed by the CSS design specification.

Issue

For RVI components and welds that have been projected to exceed the fluence threshold values, the applicant has not described the design basis methodology used to determine whether these components and welds would meet the additional criteria of the CSS design specification. Additionally, the applicant did not identify the additional criteria (e.g., acceptance limits for the strain or weld quality factor parameters requiring assessment) that the components and welds need to meet or provide the component-specific and weld-specific results of the additional analyses, as compared to the additional criteria, to demonstrate that those criteria are met.

Request

Provide the following additional information for each CSS base metal or weld component that has been projected to exceed the fluence threshold value for the component at the end of the period of extended operation.

1. Describe the design specification methodology that applies to each component and identify the additional design parameter or parameters required to be assessed by the design specification.

2. Provide the acceptance limits or acceptance criteria that apply to the component design parameters requiring further assessment.

3. Provide the calculated component-specific values for the parameters requiring further assessment by the design specification, as assessed for or projected through the end of the period of extended operation.

Response
The irradiation of Type 304 stainless steel based material to fluences greater than [[ ]] at boiling water reactor (BWR) operating temperatures results in reduced ductility and a corresponding decrease in the strain hardening exponent. Therefore, to avoid tensile instability in Type 304 stainless steel structures irradiated to fluences greater than [[ ]], the strain resulting from the combined primary and secondary stresses should be limited to less than the criteria based on the uniform strain capability of the material at the appropriate service conditions. For the Type 308 stainless steel weld material irradiated to fluences greater than [[ ]] at BWR operating temperatures, the strain resulting from the combined primary and secondary stresses should be limited to less than the criteria based on the uniform strain capability of the material at the appropriate service conditions.

The reactor vessel internals (RVI) CSS were evaluated according to the CSS design specification. For austenitic stainless steel subjected to a neutron fluence [[ ]], the base material requires no special consideration in addition to meeting the American Society of Mechanical Engineers (ASME) Code requirements. For austenitic stainless steel components with a neutron fluence [[ ]], the weld material requires no special consideration.

The design specification states that when a fluence [[ ]], that portion of the component and the weld exposed to this greater fluence shall meet the following strain criteria in the design specification in addition to the ASME Code requirements.

[[

]]

where,

P_m = Primary membrane stress
P_b = Primary bending stress
Q_m = Secondary membrane stress
Q = Secondary stress (including membrane and bending)
E = Elastic modulus
ε_{unif} = Uniform elongation

The uniform elongation ε_{unif} has [[ ]]

The specification states that SS-308 or SS-308L welds subjected to a neutron fluence [[ ]] shall either be limited to [[ ]] resulting from any operating and accident load or be [[ ]] as determined by Table NG-3352-1 of the ASME Boiler and Pressure Vessel (B&PV) Code, Section III, Subsection NG.

The fast neutron fluence values at 54 effective full power years (EFPY) (equivalent to 60 years of plant operation at 90% capacity factor) were calculated for internal CSS components and summarized in Table 1 below.

Table 1: RVI Core Support Structures Neutron Fluence

Item No.	Core Support Structure Component	Fast Fluence at 54 EFPY (n/cm^2)
1	Shroud	4.07E+21
2	[[	
		]]
3	Core Plate	5.88E+20
	Core Plate Wedges	8.36E+20
4	Top Guide/Grid	4.50E+21
5	[[	]]
6	Control Rod Guide Tube	2.32E+21
7	Orificed Fuel Support	7.64E+21
8	Peripheral Fuel Support	8.52E+20

The fluence values of the following internal CSS components exceeded [[ ]] for base material, and [[ ]] for weld material:

- Shroud
- Core Plate
- Top Guide / Grid
- Control Rod Guide Tube (CRGT)
- Orificed Fuel Support (OFS)
- Peripheral Fuel Support (PFS)

The primary and secondary stresses of the CSS components at the current licensed thermal power are the inputs used to calculate the strains at Normal/Upset, Emergency and Faulted conditions. The primary and secondary stresses are fluence-independent parameters. The strains of the components that exceed the fluence limit at 60 years of plant operation were calculated. The calculated strains are compared with the allowable strains in Table 2. The calculated strains are less than the allowable strains.

Table 2: Fluence Effect Evaluation Results (Strain)

Item No.	Core Support Structure Component(1)	Service Level(2)	Category(3)	Calculated Strain (in/in)	Allowable Strain(3) (in/in)
1	Shroud	N/U	$(P_m+Q_m) / E$	[[	
		N/U	$(P_m+P_b+Q) / E$		
		E	$(P_m+Q_m) / E$		
		E	$(P_m+P_b+Q) / E$		
		F	$(P_m+Q_m) / E$		
		F	$(P_m+P_b+Q) / E$		
2	Core Plate	U	$(P_m+Q_m) / E$		
		U	$(P_m+P_b+Q) / E$		
		E	$(P_m+Q_m) / E$		
		E	$(P_m+P_b+Q) / E$		
		F	$(P_m+Q_m) / E$		
		F	$(P_m+P_b+Q) / E$		
3	Top Guide/Grid	U	$(P_m+Q_m) / E$		
		U	$(P_m+P_b+Q) / E$		
		E	$(P_m+Q_m) / E$		
		E	$(P_m+P_b+Q) / E$		
		F	$(P_m+Q_m) / E$		
		F	$(P_m+P_b+Q) / E$		
4	Control Rod Guide Tube (CRGT)(4)	U	$(P_m+Q_m) / E$		
		U	$(P_m+P_b+Q) / E$		
		E	$(P_m+Q_m) / E$		
		E	$(P_m+P_b+Q) / E$		
		F	$(P_m+Q_m) / E$		

Item No.	Core Support Structure Component(1)	Service Level(2)	Category(3)	Calculated Strain (in/in)	Allowable Strain(3) (in/in)
		F	$(P_m+P_b+Q) / E$		
5	Orificed Fuel Support (OFS)	U	$(P_m+Q_m) / E$		
		U	$(P_m+P_b+Q) / E$		
		F	$(P_m+Q_m) / E$		
		F	$(P_m+P_b+Q) / E$		]]
6	Peripheral Fuel Support (PFS)	Bounded by Orificed Fuel Support			

Notes:
1. The most limiting location of the components is reported.
2. N = Normal condition, U = Upset condition, E = Emergency condition, F = Faulted condition.
3. Based on the fluence effect acceptance criteria.
4. P_m+Q_m stress was not calculated in the design basis. Therefore, P_m+P_b+Q stress was conservatively used as P_m+Q_m stress.

The limiting welds of the shroud and the top guide/grid subjected to the fluence [[ ]] The limiting weld stress of the control rod guide tube subjected to the fluence [[ ]]

In summary, all RVI CSS components meet the acceptance criteria of the design specification for the neutron fluence effect.

Question

RAI 3.6.2.2.2-1a (High Voltage Insulators)

LRA 3.6.2.2.2 Degradation of Insulator Quality due to Presence of Any Salt Deposits and Surface Contamination, and Loss of Material due to Mechanical Wear
(References: RAI Set 8, ML18022A941 and ML18051A531)

Regulatory Basis

Section 54.21(a)(1) of 10 CFR requires the applicant to identify and list those structures and components subject to an aging management review. Section 54.21(a)(3) of 10 CFR requires the applicant to demonstrate that the effects of aging for structures and components within the scope of license renewal and subject to an AMR pursuant to 10 CFR 54.21(a)(1) will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. As described in SRP-LR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL Report when evaluation of the matter in the GALL Report applies to the plant.

Section 3.6.2.2.2 of SRP-LR, "Reduced Insulation Resistance due to Presence of Any Salt Deposits and Surface Contamination, and Loss of Material due to Mechanical Wear Caused by Wind Blowing on Transmission Conductors" states that: "Loss of material due to mechanical wear caused by wind blowing on transmission conductors could occur in high-voltage insulators. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that this aging effect is adequately managed." The GALL report also recommends further evaluation of plant-specific AMP for potential salt deposits and surface contamination.

Background

In LRA 3.6.2.2.2, the applicant references SRP-LR for further evaluation of the above aging mechanisms and effects for high-voltage insulators. Table 3.6.1, line item numbers 3.6.1-2 and 3.6.1-3 identify the component as: "High voltage insulators composed of porcelain, malleable iron, aluminum, galvanized steel and cement." The corresponding items in Table 3.6.2 of the LRA identify the materials as: "Porcelain, galvanized metal and cement."

During the onsite audit /walkdown, the staff noted that in-scope high-voltage insulators on the 230 kV transmission lines are constructed of polymer material rather than the porcelain material listed in LRA Table 3.6.1 and Table 3.6.2. The applicant stated that the porcelain insulators had been replaced with new insulators made of polymeric material in 2008. The actual material (polymer) used in construction of the polymer in-scope high-voltage insulators are not identified in the applicant's LRA.

Staff issued RAI 3.6.2.2.2-1 to obtain clarification on why the LRA did not address the replacement components and aging effects related to polymer high-voltage insulators. The RAI and the applicant's response are documented in ADAMS Accession No. ML 18051A531, dated February 20, 2018. In its response, the applicant provided update to LRA section 3.6.2.1 as well as adding a new line item to AMR table 3.6.2 for polymer high-voltage insulators. The applicant also provided further evaluation discussions in response to RAI 2.6.2.2.2-1 for these components and concluded that there are no aging effects requiring management and did not propose a site-specific aging management program.

The staff's review of the RAI response as well as industry literature, vendor documents, RBS procedures and work orders identified some material used in the construction of the polymer high-voltage insulators that were not listed in the applicant's changes to the LRA. Specifically, according to vendor and EPRI literature provided by the applicant, the missing material include: epoxy, silicone gel, sealants, and ductile iron.

The staff's review of the RAI response and relevant technical information provided by the applicant further identified pertinent aging effects and mechanisms not addressed in the applicant's response. These include:

- Stress corrosion cracking of glass fibers
- Swelling of silicone rubber (SIR) layer due to chemical contamination

- Sheath wetting caused by chemicals absorbed by oil from SIR compound
- Brittle fracture of rods resulting from discharge activity, flashunder, and flashover
- Chalking and crazing of insulator surfaces resulting in contamination, arcing, and flashover
- Bonding failure at rod and sheathing interface
- Water ingress through end fittings causing flashunder, corrosion and fracture of glass fibers

The staff also noted that rodent and bird excrement containing aggressive chemicals such as phosphates, uric acid, and ammonia create an environment that can cause sheath layer damage and subsequent failures of the core material and fittings. Susceptibility of these components to this environment, which has not been reviewed in GALL needs to be addressed.

According to research results, aging studies and handbook material provided by the applicant, polymer insulators have been shown to have unique failure modes with little advance indications. This information also indicates that contamination can be worse for SIR (compared to porcelain insulators) due to absorption by silicone oil, especially in late stages of service life.

The staff and representatives of the applicant held a public telephone conference call on April 18, 2018, to discuss the applicant's responses to RAI 3.6.2.2.2.2-1 and issues outlined below.

<u>Issues</u>

1. The material listed in the applicant's response to RAI 3.6.2.2.2-1 seems to have omitted certain material that are used in construction of the polymer insulators. According to vendor and EPRI literature, these include: epoxy, silicone gel, sealants, and ductile iron.
2. The aging effects and mechanisms addressed in the applicant's response to RAI 3.6.2.2.2-1 seem to have addressed some, but not all relevant aging effects requiring management (AERM). The AERMs not considered in the response include the following:
   a. Stress corrosion cracking (SCC) of glass fibers due to sheath degradation
   b. Swelling of SIR layer due to chemical contamination
   c. Sheath wetting caused by chemicals absorbed by oil from SIR compound
   d. Brittle fracture of rods resulting from discharge activity, flashunder, and flashover
   e. Chalking and crazing of insulator surfaces resulting in contamination, arcing, and flashover
   f. Water penetration through the sheath followed by electrical failure
   g. Bonding failure at rod and sheathing interface
   h. Water ingress through end fittings causing flashunder, corrosion and fracture of glass fibers
3. Additionally, aggressive environment due to excrements from birds and rodents containing chemicals such as uric acid, phosphates, and ammonia that can accelerate degradation of polymers is not addressed in the applicant's response to RAI 3.6.2.2.2-1. This environment and material combination has not previously been evaluated in the GALL Report and constitutes a condition that should be assessed for RBS.
4. The applicant concluded, in its response to RAI 3.6.2.2.2-1, that an aging management program will not be implemented for polymer high-voltage insulators. The staff noted that polymer insulators have shown to have unique failure modes with little advance indications. Furthermore, contamination buildup can be worse for SIR (compared to porcelain insulators) due to absorption by silicone oil, especially in late stages of service life. It appears that t he applicant's conclusion is based on the assumption that polymer insulators are more reliable than porcelain and less likely to be affected by aging degradation, primarily due to the hydrophobic characteristics of the polymers and reduced possibility of chemicals and particulate matter buildup on the surfaces of the insulators. The staff notes that the licensee's response does not include consideration of new and unique degradation mechanisms and sensitivity to the environment, especially during later stages of service life, typically past the twenty-year period. It is not clear to the staff whether the applicant's conclusion considers all aspects of polymer insulators' degradation and aging that can result in aging effects such as reduced insulation resistance and loss of material which may require aging management.

Request

1. Explain why epoxy, silicone gel, sealants, and ductile iron are not listed in the response to RAI 3.6.2.2.2-1 as materials that are used in construction of polymer high-voltage insulators.

2. Explain why certain aging effects and mechanisms that have been identified for polymer high-voltage insulators, by industry as a result of operating experience reviews and aging study research, have not been considered in response to RAI 3.6.2.2.2-1. These aging effects and mechanisms are listed above under the heading "Issues," items 2 (a) through (h).

3. Explain why aggressive environment due to excrement from birds and rodents containing chemicals such as uric acid, phosphates, and ammonia that can accelerate degradation of polymers has not been addressed in the response to RAI 3.6.2.2.2-1. This environment and material combination has not previously been evaluated in the GALL Report and constitutes a site-specific condition to be assessed for RBS.

4. Considering polymer insulators' degradation, aging, and failure mechanisms that may require aging management, provide a discussion of any site-specific aging management program needed to ensure that the aging effects such as reduced insulation resistance and loss of material for these components composed of polymers, epoxy, silicone gel, sealants, and ductile iron will be adequately managed. Describe what parameters will be monitored or inspected to detect the AERM and how the frequency of inspection will be established. If no program will be used, justify why loss of material, reduced insulation resistance, presence of deposits, rod fiber glass degradation, SCC of fiber glass material, wetting and swelling of SIR, accelerated aging of polymer material due to discharge current activity and corona, chalking and crazing of surfaces, tracking, corona, loosening of sheath layers, bonding failure at rod/sheath interface, separation of seals and sealants, water ingress through end fittings, and surface contamination are not applicable for the polymer high-voltage insulators exposed to air-outdoor and chemicals such as uric acid, phosphates and ammonia from birds and rodents.

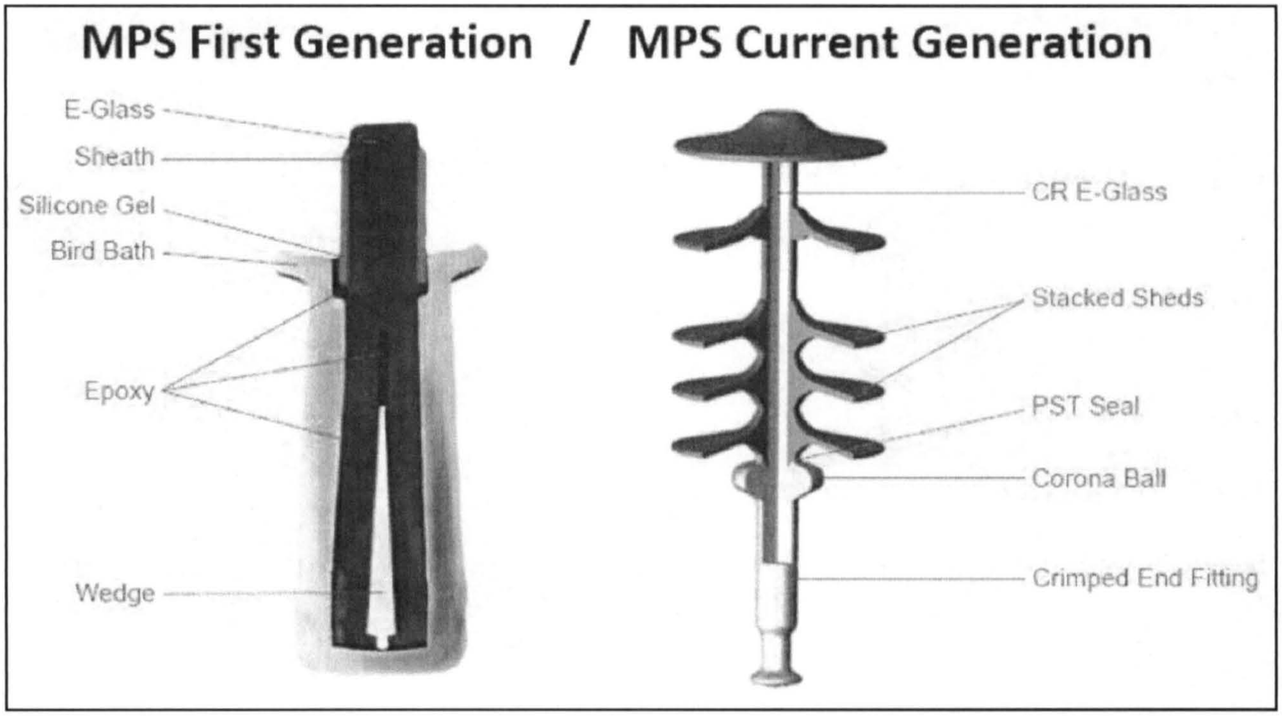
Response

Part 1

Information from the manufacturer (MacLean Power Systems or MPS) of the RBS polymer insulators does not discuss "ductile iron" for the corona ring or the end fittings, which are the only metal components on the insulators. The connection hardware does include ductile iron.

The response to RAI 3.6.2.2.2-1 stated, "The RBS polymer high-voltage insulators and connection hardware have the following materials: fiberglass, silicone rubber, aluminum and aluminum alloy, steel and steel alloys, galvanized metal (galvanized ductile iron, galvanized forged steel, steel hot dip galvanized)." Therefore, galvanized ductile iron is explicitly identified.

The RBS polymer high-voltage insulators are a recent generation of MPS polymer insulators that have been manufactured since 2007. The RBS polymer insulators do not use epoxy. The following figure shows the difference between the first generation of MPS polymer insulators and the generation of MPS polymer insulators that are used at RBS.



The MPS polymer insulators in service at RBS use a PST sealing system, which is a triple seal design. The triple seal or PST seal comprises the primary seal (P), the secondary seal (S), and the tertiary seal (T). The primary seal is a silicone rubber sheath compressed into the chamfer of the crimped end fitting. The secondary seal is RTV (room temperature vulcanizing) silicone applied to the rod, sheath, and end fitting interface. The tertiary seal is a final external RTV silicone seal applied to the sheath and end fitting interface. The RBS polymer insulators do not utilize silicone gel. The response to RAI 3.6.2.2.2-1 included silicone rubber, but did not explicitly identify RTV silicone as a type of silicone rubber. The silicone rubber material includes the RTV silicone that is part of the PST seal system. The RBS polymer insulators do not include silicone gel or sealants other than RTV silicone.

Part 2

The aging effects on polymer high-voltage insulators are the same as the aging effects on porcelain high-voltage insulators. Those aging effects are reduced insulation resistance and loss of material. Polymer degradation is an additional mechanism unique to polymer high-voltage insulators that can cause the aging effect of reduced insulation resistance.

The items identified in part 2 of the issue as Items a) through h) are discussed in the following sections. Each discussion describes how the item was considered in the aging management review of RBS polymer high-voltage insulators. The functions of high-voltage insulators are to insulate and support a high-voltage conductor. The failure of one high-voltage insulator does not cause the loss of the function of the high-voltage insulator system to insulate and support a high-voltage conductor.

a) Rod failures of early generation polymer insulators have been linked to stress corrosion cracking (SCC) resulting from infiltration of water into the fiberglass/glass reinforced plastic rod. The failures have been attributed to either acid or water leaching of the metallic ions in the glass fibers resulting in stress corrosion cracking. SCC in an E-glass polymer composite results from the combined effect of low mechanical tensile stresses applied along the fibers and chemical attack of either organic or inorganic acids. Known in the industry as brittle fracture this failure of the polymer insulator rods is generally associated with high-voltage applications in which nitric acid or other acids can be present. In order to avoid such failures, water is prevented from migrating into the end fittings of polymer insulators. In-service failures have been observed when nitric acid forms and reaches the rod surface. The polymer high-voltage insulators installed on the 230 kV offsite power recovery paths for RBS are specifically manufactured to eliminate the conditions that can cause brittle fracture of the polymer insulator support rod. For these insulators, the fiberglass rod is a boron-free corrosion-resistant (CR) E-Glass, which is resistant to nitric acid attacks. There has never been a brittle facture failure of a CR E-glass rod in an MPS polymer insulator in over 30 years of use. Review of industry literature applicable to RBS polymer high-voltage insulators did not identify any aging effects requiring management related to brittle fracture of the glass support rods.

b) Swelling of SIR layer due to chemical contamination is not identified in industry documents as a cause of loss of function in high-voltage polymer insulators. One industry document, published in October 2003, discusses that solvents can swell polymers, and that some polymer characterization tests are based upon the degree of swelling of the unknown polymer in different solvents; the swelling ratios can fingerprint the polymer. The other discussion of swelling in this document is that studies could be performed to determine chemical environments (unique chemicals or cocktails) that would theoretically assess the potential for swelling or other degradation that could change the water permeability or hydrophobic properties of the water shed polymer. No studies were found for using solvents to create potential problems for silicone rubber polymers. Also, solvents are not found in the air environment of high-voltage insulators at RBS. Review of industry literature for the type of polymer insulator used at RBS did not identify any aging effects requiring management related to swelling of silicone rubber insulator components due to chemical contamination for polymer high-voltage insulators.

c) Sheath wetting caused by chemicals absorbed by oil from SIR compound was not found as a failure cause for polymer insulators. Discussions of sheath wetting were not identified for polymer insulators. There are industry documents that contain statements from an old reference citing that silicone rubber insulators, due to the presence of the silicone oils, collect more contaminants than glass or ceramic surfaces. Later industry documents refuted this old reference, by stating that silicone rubber is naturally hydrophobic, has excellent resistance to UV, and minimizes leakage currents on the surface of the insulator, all of which help polymer insulators perform well in contaminated environments. This position was discussed in greater detail in the response to RAI 3.6.2.2.2-1. Review of industry literature for the type of polymer insulator used at RBS did not identify any aging effects requiring management related to sheath wetting caused by chemical absorption for polymer high-voltage insulators.

d) Failure of rods resulting from discharge activity, flashunder, and flashover is not called brittle facture in industry documents. Brittle fracture due to stress corrosion cracking is discussed in item 2(a) above. Flashover occurs external to the sheath covering the rod; therefore, flashover is not applicable to failure of the rod by discharge activity. Flashunder is initiated by tracking along or through the rod under the silicone rubber sheath and occurs when internal discharge activity results in carbonization within or on the surface of the fiberglass rod. Failure of the rod caused by discharge activity and flashunder are relatively slow degradation processes resulting from discharges in or along the rod. These discharges could occur when the rod is exposed to the environment because of a functional failure of either the rubber weathershed system or the end fitting seal. The MPS polymer high-voltage insulators are specifically manufactured to preclude these degradation processes. The CR E-Glass rod is housed in a concentric extruded seamless sheath of silicone rubber. The sheath and the sealing system of the MPS polymer high-voltage insulators prevent exposure of the rod to the environment, which mitigates or eliminates destruction of the rod by discharge activity and flashunder. Review of industry literature for the type of polymer insulator used at RBS did not identify any aging effects requiring management related to failure of the rod by discharge activity and flashunder for polymer high-voltage insulators.

e) Chalking and crazing of insulator surfaces resulting in contamination, arcing, and flashover are discussed in industry documents for first-generation polymer insulators. Typical problems encountered with first-generation polymer insulators included chalking and crazing after a few years of operation. Chalking is a microstructure change on the surface of the insulator forming a powdery surface; however, based on testing, service-aged silicone rubber insulators still maintain acceptable hydrophobic properties with the presence of chalking. Crazing is defined as the formation of surface cracks that do not affect the operating characteristics of the insulator. Crazing may be an early indicator of insulator degradation. Review of industry literature did not identify any aging effects requiring management related to chalking and crazing of silicone insulator surfaces as an aging mechanism for more recent generations of polymer insulators, which are used at RBS.

f) Water penetration through the sheath followed by electrical failure is discussed in industry documents for first-generation polymer insulators. One failure mode observed in first-generation polymer insulators was water penetration followed by electrical failure after a few years of operation. This is not discussed as an aging mechanism for more recent generations of polymer insulators, which are used at RBS. The discussion in 2(d) provides the information relevant to water penetration into the rod for RBS polymer insulators.

g) Bonding failure at rod and sheathing interface is discussed in industry documents for first-generation polymer insulators. Failure modes observed in first-generation polymer insulators included bonding failures and breakdowns along the rod-sheath interface after a few years of operation. There were several discussions of poor bonding of the end fittings, and this is discussed as a mechanical failure. There are manufacturer tests now for identifying poor bonding of the end fittings. End fittings used on RBS insulators are attached using a controlled / automated crimping process to achieve the required tensile strength. The end fittings are forged steel, galvanized for protection against corrosion. Therefore, this design mitigates or eliminates mechanical failures. The discussion in 2(a) for SSC and 2(d) for water penetration into the rod provides the information relevant to RBS polymer insulators.

h) Water ingress through end fittings causing corrosion and fracture of glass fibers is discussed with references to operating experience for early or first-generation polymer insulators. Most of the discussions of water ingress, immersion, penetration, or diffusion are associated with testing standards for manufacturers. This is not discussed as a failure cause for later-generation polymer insulators. The discussions in 2(a) for SSC, 2(d) for water penetration into the rod, and 2(g) for bonding failures provide the information relevant to RBS polymer insulators.

Industry operating experience was summarized for polymer insulators in the response to RAI 3.6.2.2.2-1. This operating experience provided information on failures from EPRI's polymer insulator database and included specific information on failures of MPS polymer insulators. In addition, the response to RAI 3.6.2.2.2-1 provided information on aging studies performed for polymer insulators. The applicable aging mechanisms and stressors identified by the industry for polymer high-voltage insulators were considered as part of the operating experience and aging studies discussion in the response to RAI 3.6.2.2.2-1, and as part of the aging effects evaluation for polymer high-voltage insulators. The aging effects of reduced insulation resistance due to deposits or surface contamination, loss of material due to mechanical wear caused by wind blowing on transmission conductors, and reduced insulation resistance due to polymer degradation were discussed.

Part 3

Based on a search of industry documents, degradation of polymer insulators from "bird" and "rodent" excrement was not identified. An industry document providing guidance on the selection, specification, and procurement of composite insulators for transmission lines discussed advantages and disadvantages for different insulator technologies including older generation composite insulators. For composite insulators, "Susceptible to damage from birds and rodents" was postulated as a disadvantage, but there was no operating experience or aging studies cited for this claim.

An environment due to excrement from rodents is not applicable to the transmission conductor polymer high-voltage insulators. Site operating experience has not identified an environment due to excrement from birds for the transmission conductors, the polymer high-voltage insulators, or the porcelain high-voltage insulators. Therefore, there is not an aggressive environment due to excrement from birds and rodents containing chemicals such as uric acid, phosphates, and ammonia for polymer high-voltage insulators.

Part 4

As discussed in the in the response to RAI 3.6.2.2.2-1, the following aging effects for polymer high-voltage insulators were evaluated.

- reduced insulation resistance due to deposits or surface contamination
- loss of material due to mechanical wear caused by wind blowing on transmission conductors
- reduced insulation resistance due to polymer degradation

As stated in the response to RAI 3.6.2.2.2-1, the aging effect of loss of material due to mechanical wear caused by wind blowing on transmission conductors is the same for polymer high-voltage insulators as for porcelain high-voltage insulators. The end components and the connection hardware for the polymer high-voltage insulators are similar in design and material to those of the porcelain high-voltage insulators. As discussed in LRA Section 3.6.2.2.2 for porcelain high-voltage insulators, loss of material (wear) and fatigue that could be caused by transmission conductor vibration or sway are not applicable aging effects in that they would not cause a loss of intended function if left unmanaged for the period of extended operation. LRA Table 3.6.2 was updated to include a polymer insulator line item to align with Table 3.6.1, Item 3.6.1-2.

For discussions of aging management and LRA Table 3.6.2, the other two aging effects listed in the response to RAI 3.6.2.2.2-1 were combined into reduced insulation resistance. As previously indicated, reduced insulation resistance is the aging effect, which can be due to the mechanisms of polymer degradation or surface contamination.

While reduced insulation resistance is not expected, RBS will include preventive maintenance activities in the Periodic Surveillance and Preventive Maintenance Program to provide assurance that the effects of aging will not prevent the polymer high-voltage insulators from continuing to perform their intended function during the period of extended operation.

Preventive maintenance activities will include performing a corona scan (UV) and visual inspection of polymer high-voltage insulators on the RSS#1 and RSS#2 lines to the plant every 6 years to detect indications of reduced insulation resistance.

The changes to LRA Table 3.6.2, and Sections A.1.34 and B.1.34 follow with additions underlined and deletions lined through.

Table 3.6.2: Electrical and I&C Components

Structure and/or Component or Commodity	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
High-voltage insulators – Polymer (high-voltage insulators for SBO recovery)	IN	Fiberglass, silicone rubber, aluminum and aluminum alloy, steel and galvanized metals	Air – outdoor	~~None~~ Reduced insulation resistance	~~None~~ Periodic Surveillance and Preventive Maintenance	--	--	F
High-voltage insulators – Polymer (high-voltage insulators for SBO recovery)	IN	Fiberglass, silicone rubber, aluminum and aluminum alloy, steel and galvanized metals	Air – outdoor	None	None	VI.A.LP-32 VI.A-10 (LP-11)	3.6.1-2	I

A.1.34 Periodic Surveillance and Preventive Maintenance

Credit for program activities has been taken in the aging management review for the following components or commodities.

- Inspect the surface of the polymer high-voltage insulators for transmission conductors on the RSS#1 and RSS#2 lines
- Perform corona scans (UV) of the polymer high-voltage insulators for transmission conductors on the RSS#1 and RSS#2 lines

B.1.34 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE

Credit for program activities has been taken in the aging management review for the following commodities, systems and structures.

Polymer high-voltage insulators for the transmission conductors on the RSS#1 and RSS#2 lines	Perform a corona scan (UV) of polymer high-voltage insulators to detect reduced insulation resistance due to deposits or surface contamination, and reduced insulation resistance due to polymer degradation.
Polymer high-voltage insulators for the transmission conductors on the RSS#1 and RSS#2 lines	Perform a visual inspection of the polymer high-voltage insulators to detect deposits or surface contamination, and loss of material due to mechanical wear.

Question
Operating Experience Review Clarification

Background
LR-ISG-2011-05, "Ongoing Review of Operating Experience," provides guidance on the review of operating experience during the period of extended operation. LR-ISG-2011-05, Appendix A describes the "Acceptable Use of Existing Programs," and also, "Areas of Further Review."

Appendix A notes in "Areas of Further Review:"

> "The programmatic activities for the ongoing review of plant-specific and industry experience concerning age-related degradation and aging management should be described in the license renewal application, including the FSAR supplement," and
>
> "Alternate approaches for the future consideration of operating experience are subject to NRC review on a case-by-case basis."

Issue
The license renewal application (LRA) should address the information contained in the ISG, including the "Acceptable Use of Existing Programs," and, "Areas for Further Review," whether the guidance is followed or an alternative approach is presented for the staff's review.

The staff's determined that LRA, Appendix B, Section 5.0.4 [sic], addressed the guidance contained in LR-ISG-2011-05, Appendix A, "Acceptable Use of Existing Programs."

However, the staff did not determine that the LRA addressed the following items of LR-ISG-2011-05, Appendix A, "Areas of Further Review," or provided an alternative approach:

- All revisions to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," should be considered as a source of operating experience and evaluated accordingly. NRC and industry guidance documents and standards applicable to aging management also should be considered as sources of operating experience. There should be written plans and expectations for identifying such documents and processing them as operating experience.

- All incoming plant-specific and industry operating experience should be screened to determine whether it may involve age related degradation or impacts to aging management activities.

- A specific identification code (i.e., "Aging") should be used in the corrective action program to identify operating experience concerning age-related degradation applicable to the plant. A definition should be provided so that this code can be assigned consistently by plant personnel. The entries associated with this code should be periodically reviewed to determine whether trending is necessary. Any adverse trend should be entered into the corrective action program for evaluation.

- Operating experience items identified as potentially involving aging should receive further evaluation. This evaluation should specifically take into account the following: (a) systems, structures, and components, (b) materials, (c) environments, (d) aging effects, (e) aging mechanisms, (f) AMPs, and (g) the activities, criteria, and evaluations integral to the elements of the AMPs. The assessment of this information should be recorded with the operating experience evaluation. If it is found through evaluation that any effects of aging may not be adequately managed, then a corrective action should be entered into the 10 CFR Part 50, Appendix B, program to either enhance the AMPs or develop and implement new AMPs

- The results of implementing each AMP (i.e., data from inspections, tests, analyses, etc.) should be evaluated to determine whether the effects of aging are adequately managed. These evaluations should be conducted regardless of whether the acceptance criteria of the particular AMP have been met. A determination is made as to whether the frequency of future inspections should be adjusted, whether new inspections should be established, and whether the inspection scope should be adjusted or expanded. If there is an indication that the effects of aging may not be adequately managed, then a corrective action is entered into the 10 CFR Part 50, Appendix B, program to either enhance the AMP or develop and implement new AMPs.

- Any enhancements necessary to fulfill the above criteria should be put in place no later than the date the renewed operating license is issued and implemented on an ongoing basis throughout the term of the renewed license.

- The programmatic activities for the ongoing review of plant-specific and industry experience concerning age-related degradation and aging management should be described in the license renewal application, including the FSAR supplement. Alternate approaches for the future consideration of operating experience are subject to NRC review on a case-by-case basis.

Staff Request
The staff requests that the applicant indicate how the guidance listed in the identified items of the LR-ISG-2011-05, Appendix A, "Areas of Further Review," (as listed above) is met by the applicant's operating experience program, as enhanced and documented in the USAR supplement, or provide an alternative approach for the staff's review.

Response
To clarify how the guidance listed in LR-ISG-2011-05, Appendix A, "Areas of Further Review," is met by the RBS operating experience program, additional information is provided in LRA Appendix A, Updated Safety Analysis Report Supplement, Section A.1. LRA Section A.1 of the USAR supplement includes a summary description of the activities for ongoing review of the operating experience. On issuance of the renewed license, this summary description will be incorporated into the licensing basis.

The changes to LRA Appendix A, Section A.1 follow with additions underlined.

The integrated plant assessment for license renewal identified aging management programs necessary to provide reasonable assurance that structures and components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. This section describes the aging management programs and activities required during the period of extended operation. Aging management programs will be implemented prior to entering the period of extended operation.

The corrective action, confirmation process, and administrative controls of the RBS (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities during the period of extended operation. RBS quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B. The RBS Quality Assurance Program applies to safety-related and important to safety structures and components. Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished in accordance with the established RBS corrective action program and document control program and are applicable to all aging management programs and activities during the period of extended operation. The confirmation process is part of the corrective action program and includes reviews to assure adequacy of corrective actions, tracking and reporting of open corrective actions, and review of corrective action effectiveness. Any follow-up inspection required by the confirmation process is documented in accordance with the corrective action program.

Operating experience from plant-specific and industry sources is identified and systematically reviewed on an ongoing basis. The RBS corrective action program, which is implemented in accordance with the quality assurance program, effects the documentation and evaluation of plant-specific operating experience. The RBS operating experience program, which meets the provisions of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff," systematically evaluates industry operating experience. The operating experience program includes active participation in the Institute of Nuclear Power Operations' operating experience program, as endorsed by the NRC.

Codes are used in the corrective action program that provide for the comprehensive identification and categorization of aging-specific issues for plant systems, structures, and components within the scope of license renewal.

In accordance with these programs, site-specific and industry operating experience items are screened to determine whether they involve lessons learned that may impact aging management programs (AMPs). Items are evaluated, and affected AMPs are either enhanced or new AMPs are developed, as appropriate, when it is determined that the effects of aging are not adequately managed. Plant-specific operating experience associated with managing the effects of aging is reported to the industry in accordance with guidelines established in the operating experience review program.

The results of implementing aging management programs (e.g., data from inspections, tests, analyses) are evaluated to determine whether the effects of aging are adequately managed. These evaluations are conducted regardless of whether the acceptance criteria of the particular AMP have been met. A determination is made as to whether the frequency of future inspections should be adjusted, whether new inspections should be established, and whether the inspection scope should be adjusted. If the effects of aging are not being adequately managed, then a corrective action is entered into the 10 CFR Part 50, Appendix B, program to either enhance the AMP or develop and implement new aging management activities.

Training provided for personnel responsible for submitting, screening, assigning, evaluating, or otherwise processing plant-specific and industry operating experience, as well as for personnel responsible for implementing AMPs, is based on the complexity of the job performance requirements and assigned responsibilities. Training is scheduled on a recurring basis, which accommodates the turnover of plant personnel and the need for new training content.

Revisions to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report" are developed to incorporate lessons learned from LRA reviews and from relevant industry operating experience. For Revision 2, NRC staff reviewed industry operating experience for the period from January 2004 to approximately April 2009 to identify recommended modifications to the GALL Report. The staff from the Division of License Renewal (DLR) analyzed operating experience information during a screening review of domestic operating experience, foreign operating experience from the international Incident Reporting System database, and NRC generic communications. The operating experience review program at RBS includes review of operating experience from the same domestic and foreign sources and from NRC generic communications Thus, the RBS operating experience review program includes the review of operating experience documented within each revision of NUREG-1801.

Evaluation of operating experience related to managing the effects of aging includes the consideration of affected plant systems, structures, and components; materials; environments; aging effects, aging mechanisms; aging management programs (AMPs); and the activities, criteria, and evaluations integral to the aging management programs.

RBG-47861

ENCLOSURE 2

COMMITMENT

This table identifies actions discussed in this letter that Entergy commits to perform. Any other actions discussed in this submittal are described for the NRC's information and are **not** commitments.

Changes to LRA Section A.4 follow with additions underlined.

A.4 LICENSE RENEWAL COMMITMENT LIST

No.	Program or Activity	Commitment	Implementation Schedule	Source (Letter Number)
24	Periodic Surveillance and Preventive Maintenance	Enhance the PSPM Program as described in LRA Section A.1.34.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735 RBG-47861