Entergy

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Stephen J. Bethay
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March 16, 2011

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

SUBJECT: Entergy Nuclear Operations, Inc.
Pilgrim Nuclear Power Station
Docket No. 50-293
License No. DPR-35

Pilgrim Nuclear Power Station (PNPS) License Renewal Application (LRA) Supplemental Information

REFERENCES:

1. Entergy Letter No. 2.06.003, to USNRC, "Entergy Nuclear Operations Inc., License No. DPR-35, License Renewal Application," dated January 25, 2006.
2. Entergy Letter No. 2.11.001 to USNRC, "Pilgrim Nuclear Power Station (PNPS) License Renewal Application (LRA) Supplemental Information," dated January 7, 2011
3. Entergy Letter No. 2.11.008 to USNRC, "Pilgrim Nuclear Power Station (PNPS) License Renewal Application (LRA) Additional Supplemental Information," dated January 31, 2011

LETTER NUMBER: 2.11.017

Dear Sir or Madam:

On January 25, 2006, Entergy Nuclear Operations, Inc. (Entergy) submitted the License Renewal Application (LRA) for the Pilgrim Nuclear Power Station (PNPS) as indicated by Reference 1.

On January 7, 2011 and January 31, 2011 (References 2 and 3), Entergy provided additional information that supplemented the LRA as a result of operating experience (OE) and industry activities potentially relevant to aging management in several specific areas.

This letter provides further clarification of that supplemental information to the LRA specific to the following areas which Entergy agreed to evaluate based upon communications with the NRC technical staff.

1. Aging management of neutron-absorbing materials

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2. Inspection of buried pipe and tanks
3. Aging management of low voltage cables
4. Inspection of containment coatings
5. Metal fatigue NUREG/CR-6260

A new regulatory commitment is provided in the PNPS License Renewal Commitment List as Attachment 2.

Should you have any questions or require additional information concerning this submittal, please contact Mr. Joseph R. Lynch at 508-830-8403.

I declare under penalty of perjury that the foregoing is true and correct. Executed on March 16, 2011.

Sincerely,

Stephen J. Bethay

Stephen J. Bethay
Director Nuclear Safety Assurance

JRL/jl

Attachments: 1. License Renewal Application Supplemental Information (18 Pages)
2. License Renewal Commitment List (2 Pages)

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Attachment 1 to Letter No. 2.11.017

Pilgrim Nuclear Power Station
License No. DPR-35 (Docket No. 50-293)

License Renewal Application

Supplemental Information

Pilgrim Nuclear Power Station
License Renewal Application - Supplemental Information

Entergy provides the following additional supplemental information as a result of operating experience (OE) and industry activities potentially relevant to aging management in the following areas at Pilgrim Nuclear Power Station (PNPS).

- Neutron-Absorbing Material
- Buried Piping and Tanks
- Low-Voltage Cables
- Protective Containment Coatings
- Metal Fatigue NUREG/CR-6260

Neutron-Absorbing Material

Pilgrim Nuclear Power Station (PNPS) provides the following supplemental information to address questions discussed with the NRC staff during a teleconference held on January, 19, 2011.

Discussion

PNPS will use coupon testing for the Boral and Metamic materials in the spent fuel pool (SFP) racks. The coupons will be analyzed to measure B-10 areal density and geometric changes (i.e. blistering, pitting and bulging). The primary parameter to be monitored during the period of extended operation (PEO) is B-10 areal density. When analyzing coupons, a number of measurements will be made of the areal density of each coupon and geometric or physical (blistering, pitting and bulging) changes will be identified, recorded, and evaluated.

The initial testing will be completed prior to entering the PEO to confirm that the boron areal density of the material will continue to meet the assumptions of the SFP criticality analysis. Degradation noted during testing or problems noted during spent fuel movement will be entered into the PNPS corrective action program and evaluated. In accordance with the recommendations of NUREG-1801, the frequency of testing during the PEO will be at least once every ten years. The interval between tests will be shortened if the results of the PNPS testing or testing of similar materials at other Entergy facilities or industry operating experience indicate that unacceptable degradation may occur prior to the next scheduled test.

The following describes the 10 elements of the PNPS Neutron Absorber Monitoring Program.

B.1.35 NEUTRON ABSORBER MONITORING PROGRAM

Program Description

The Neutron Absorber Monitoring Program is a new aging management program that manages loss of material and reduction of neutron absorption capacity of Boral and Metamic neutron absorption panels in the spent fuel racks. The program will rely on periodic inspection, testing, monitoring and analysis of the criticality design to assure that the required five percent subcriticality margin is maintained during the period of extended operation.

The program will be initiated prior to the PEO.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program manages the effects of aging on Boral and Metamic neutron absorption panels used in spent fuel racks at PNPS.

2. ***Preventive Actions:*** This program is a condition monitoring program without preventive actions.

3. ***Parameters Monitored/Inspected:*** The parameters monitored include the physical condition of the Boral and Metamic neutron-absorption panels including geometric changes in the material (formation of blisters, pits, and bulges) as observed from coupons. The primary parameter to be monitored is B-10 areal density.

4. ***Detection of Aging Effects:*** Loss of material and degradation of the neutron absorption capacity will be determined through coupon testing of each material. Coupon testing will measure B-10 areal density and geometric changes (I.e. blistering, pitting and bulging). A number of measurements are made of the areal density of each coupon and then averaged. Any geometric or physical changes (blistering, pitting and bulging) will be identified, recorded and evaluated.

   The frequency of the inspection and testing will be at least once every 10 years. The interval between tests will be shortened if the results of the PNPS testing, testing of similar materials at other Entergy facilities, or industry operating experience indicate that unacceptable degradation may occur prior to the next scheduled test.

5. ***Monitoring and Trending:*** The measurements from periodic inspections and analysis results will be compared to prior measurements and analysis results for trending.

6. ***Acceptance Criteria:*** Testing will confirm that the Boral and Metamic panels continue to meet the minimum B-10 areal density assumptions of the spent fuel pool criticality analysis. Changes in physical dimensions will be evaluated for acceptability under the corrective action program.

7. ***Corrective Actions:*** If a) the results from measurements and analysis indicate that the 5% sub-criticality margin cannot be maintained because of current or projected degradation of the neutron-absorbing material, b) degradation is noted during testing, or c) problems are observed during fuel movement in the SFP racks, the condition will be entered into the corrective action program. The corrective action controls of the PNPS (10 CFR Part 50, Appendix B) Quality Assurance Program address corrective actions under this program.

8. ***Confirmation Process:*** The requirements of the PNPS (10 CFR Part 50, Appendix B) Quality Assurance Program address the confirmation process.

9. ***Administrative Controls:*** The requirements of the PNPS (10 CFR Part 50, Appendix B) Quality Assurance Program address administrative controls.

10. ***Operating Experience:*** Some of the industry operating experience with neutron absorbing material is listed below.

    a) Loss of material from neutron absorbing material has been seen at some plants, including loss of aluminum, which was detected by monitoring the aluminum concentration in the spent fuel pool. One instance of this was documented in the Vogtle LRA Water Chemistry Program B.3.28.

b) Blistering has also been noted at some plants. Examples include blistering at Seabrook and Beaver Valley.

c) Loss of neutron-absorbing capacity of the plate-type carborundum material has been reported at Palisades.

In addition to the above, additional relevant industry operating experience is described in LR-ISG-2009-01. Relevant operating experience will be considered during implementation of this program.

Conclusion

The Neutron Absorber Monitoring Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

A.2.1.41 Neutron Absorber Monitoring Program

The Neutron Absorber Monitoring Program is a program that manages loss of material and reduction of neutron absorption capacity of Boral and Metamic neutron absorption panels in the spent fuel racks. The program will rely on periodic inspection, testing, monitoring of coupons, and analysis of the criticality design to assure that the required five percent subcriticality margin is maintained during the period of extended operation.

The program will be initiated prior to the period of extended operation.

Buried Piping and Tanks

Background:

In a December 6, 2010, telephone conference with the applicant, the staff discussed the fact that since the November 2007 issuance of NUREG-1891, "Safety Evaluation Report Related to the License Renewal of Pilgrim Nuclear Power Station," there have been a number of examples of industry operating experience involving the corrosion of buried and underground piping and tanks within the scope of license renewal. The staff requested additional information from the applicant in light of the available operating experience and in order to ensure the aging effects for buried and underground piping and tanks will be managed such that these systems and components will continue to perform their intended functions throughout the period of extended operation. The applicant provided additional information related to their buried piping program in a letter dated January 7, 2011. Based on the information provided, the staff concluded that additional detail is needed, as discussed below.

Request:

As to all in-scope buried pipes and tanks, except for the salt service water outflow piping and the condensate storage system:

1. State the specific number and types of inspections that will be conducted during the ten years prior to the period of extended operation and during each of the ten-year periods within the period of extended operation. The number and types of inspections should differentiate between material type, code/safety-related function of the component, and piping contents.

   Response: The fire protection system piping is cast iron and ductile iron which was conservatively assumed to be gray cast iron for the License Renewal Application (LRA). Ductile iron and gray cast iron have very similar corrosion resistance with ductile iron being less susceptible to selective leaching. Ductile iron has higher tensile strengths than grey cast iron. As discussed in Pilgrim (PNPS) letter 2.11.001 dated January 7, 2011 (Reference 1), PNPS adopted NFPA 25 flow testing on an annual frequency, which ensures the effects of aging on fire protection system piping will be adequately managed. No inspections are necessary for the buried salt service water system inlet piping since it was replaced with titanium piping for its very high resistance to corrosion.

   PNPS will excavate and visually inspect the protective coating on in-scope carbon steel (CS) piping systems as described below.

   SBO Diesel Piping, Fuel Oil System and Coolant System

   Prior to the PEO, PNPS will excavate and inspect 30 feet of the SBO diesel fuel oil pipe, and 20 feet of the SBO diesel coolant piping. These visual inspections will be conducted at least once every 10-years during the PEO.

   EDG Fuel Oil System

   Prior to the PEO, PNPS will excavate and inspect 30 feet of EDG fuel oil pipe. This visual inspection will be conducted at least once every 10-years during the PEO.

Standby Gas Treatment System (SBGTS)

Prior to the PEO, PNPS will excavate and inspect 20-feet of SBGTS pipe. This visual inspection will be conducted at least once every ten years during the PEO.

A single excavation is planned for each system allowing full access to the percentage of system piping specified below.

(Period of Extended Operation = PEO, Station Blackout = SBO, SBO Fuel Oil = SBOFO), Emergency Diesel Generator Fuel Oil = EDGFO, Standby Gas Treatment = SBGT))

System	Safety Class	Material	Contents	10-years prior to PEO	1st 10-years of PEO	2nd 10-years of PEO
SBO cooling water	II	CS	Treated Water	>10%	>10%	>10%
SBOFO	II	CS	Fuel Oil	>10%	>10%	>10%
EDGFO	I	CS	Fuel Oil	7%	7%	7%
SBGT	I	CS	Air	3%	3%	3%

2. State the length of piping that was excavated and visually inspected by system for inspections conducted after June 2002. Summarize the inspection results for each of these inspections.

   Response: No inspections have occurred since June of 2002; however the scope of inspections planned in the 10-year period prior to the PEO is summarized in the response to question 1 (above).

3. State the quality of backfill found during excavated inspections of buried pipe.

   Response: Reports from field personnel regarding out of scope piping excavations indicate the backfill on site complies with Bechtel Specification for Pilgrim Station, 6498-C-36.

   Specification 6498-C-36- Specification for General Site Grading and Structural Fill, Section 7.0 Bedding and Backfill for Underground Utilities and Tanks states the bedding and backfill:

   "... (is) composed of clean, free draining sand, ... deposited in the trench and thoroughly tamped to obtain a firm and uniform support. There shall be no stones in the bottom of the trench or no ledge or rock within six inches of the bottom of the pipe barrel....Backfill shall be placed in uniform six (6) inch maximum loose layers from the top of the bedding to an elevation 2 feet above the top of the pipe and compacted....Materials within six inches of coated pipe,...underground tanks and electrical utilities shall be 3/8" maximum...".

   A recent review of photographs taken during construction show buried piping being installed in clean backfill. The installed backfill condition will be further assessed as in-scope pipes are excavated for inspection.

4. For buried in-scope steel piping in the salt service water (intake piping only) and standby gas treatment systems without cathodic protection:

a. State how plant-specific operating experience (e.g., significant coating degradation, significant piping or tank degradation, unacceptable materials in backfill) and localized soil conditions will be factored into increased inspections, including the specific increase in the number of committed inspections by material type and location.

Response: Soil testing and backfill inspections will be performed during excavations. With soil resistivity < 20,000 ohm-cm, or the soil scores higher than 10 points using American Water Works Association (AWWA) C105, or if backfill is found to have damaged the coating, the length of SBGTS pipe inspected will be doubled during subsequent 10 year inspections. The salt service water (SSW) intake piping is titanium, and is not susceptible to corrosion in a soil environment.

b. State what localized soil parameters, beyond soil resistivity and soil drainage (e.g., pH, sulfates, chlorides), will be obtained in order to inform inspection locations and population size. State how often and where localized soil data samples will be obtained both before and during the period of extended operation.

Response: Soil samples will be taken at a minimum of two locations at least three feet below the surface near the in-scope piping to obtain representative soil conditions. The parameters monitored will include soil resistivity, pH, redox potential, moisture and sulfides. AWWA Standard C105 Appendix A is used to determine corrosiveness of the soil in addition to soil resistivity. Measurements will be taken during each excavation.

5. State how many fiberglass fuel oil tanks are in-scope. If the fuel oil system contains a buried in-scope fiberglass fuel oil tank, state why there are no aging effects requiring management given that the tank may be susceptible to blistering, spalling, or cracking due to water infiltration.

Response: There are two in-scope buried fiberglass tanks and they contain fuel oil for the SBO diesel generators. These are double walled tanks and a monitor will detect leakage, if any, into the space between the walls from either the inside or the outside of the tank. The interstitial space monitor alarms at the SBO panel and sends a trouble alarm to the main control room.

There are no aging effects requiring management for fiberglass in a soil environment. This conclusion is based on the fact that the fiberglass tanks are not exposed to ultraviolet light, ozone or high voltage currents, and the tanks are located above the water table such that they are not continuously exposed to water nor subjected to hydraulic pressures whereby the water could penetrate the gelcoat, enter the underlying laminate and cause blistering.

6. State the availability of the cathodic protection system, and if portions of the system are not available 90 percent of the time or will be allowed to be out of service for greater than 90 days in any given year, state what increased number of inspections will occur in order to provide reasonable assurance that the piping system will meet its current licensing basis function.

Response: Pilgrim maintains its cathodic protection system available >90% of the time. Should system availability drop below 90%, for greater than 90 days in any given year, a condition report would be initiated with the corrective actions to include consideration of increased inspections, in order to provide reasonable assurance the protected piping system will meet its current licensing basis function.

7. For buried in-scope steel fuel oil tanks:

   a. State whether the top and side surfaces of the tank will be examined by the ultrasonic method, or state why it is acceptable to not examine the top and side surfaces of the tanks.

   Response: Pilgrim inspected the buried EDG 'A' and 'B' fuel oil tanks in 1998. In 2010 a, re-inspection of 'A' tank was performed with the results indicating no reduction in wall thickness from previous readings. Pilgrim performed UT inspections from the bottom of the tank up to approximately 2 ft from the top of the tank along the walls and ends. The tanks are 10-foot diameter cylinders, lying on their sides with no geometry that would promote water accumulation on top of the tanks. The tanks are installed above the groundwater table and the areas around the tanks were backfilled with free draining sand; therefore the lower surfaces of the tanks are representative of the external conditions that would be found near the top of the tanks.

   b. State the minimum coverage of the ultrasonic examinations. If the number of inspection points are less than one measurement per square foot of tank surface, state the basis for why the ultrasonic examination provides reasonable assurance that the tank will be able to meet its current licensing basis function.

   Response: The LRA commitment was to continue the existing program for EDG underground storage tank inspections when the inspection was performed in June 2010. The latest inspection included the same areas as previous inspections to permit trending of wall degradation. Pilgrim visually inspected 100% of the interior surface of EDG Tank 'A' and ultrasonically examined 96 discrete locations covering greater than 70% of that surface. The examinations focused on those locations potentially susceptible to degradation and no measurable degradation was noted. There is margin between the calculated minimum required wall thickness of 0.337" and the lowest measured wall thickness of 0.390". This lack of measurable degradation in tank wall thickness provides reasonable assurance that the tank will be able to meet its current licensing basis function during the PEO.

   c. State the frequency of inspection of the tanks. If the frequency of tank inspections exceeds ten years, state the basis for why test frequency provides reasonable assurance that the tank will be able to meet its current licensing basis function.

   Response: The tanks are inspected on a 10-year frequency in accordance with plant Preventive Maintenance schedules. In addition, they are subject to pressure testing including the attached piping on annual basis in accordance with State requirements.

8. For the following alternative testing methods state the following:

   a. For pressure testing: percent of piping to be pressure tested for each material, test pressure, holding time, and frequency of testing. If the pressure test covers less than 25 percent of the linear feet of piping for the material type, or test pressure is less than 125 percent of maximum allowable working pressure, or hold time is less than eight hours, or the frequency exceeds five years, state why the pressure test provides reasonable assurance that the piping will meet its current licensing basis function. In addition, state how the acceptance criteria will be developed such that the piping system's current licensing basis function of maintaining sufficient pressure and providing flow will be met.

Response: PNPS is not using alternate testing methods such as pressure tests in lieu of visual piping inspections.

b. For ultrasonic thickness measurements: percent of piping to be examined for each material, whether the test method will be capable of detecting pitting, and frequency of testing. If the ultrasonic examination covers less than 25 percent of the linear feet of piping for the material type, or the test cannot detect pitting, or the frequency exceeds five years, state why the ultrasonic examination provides a reasonable assurance that the piping will meet its current licensing basis function.

Response: PNPS is not using alternate testing methods such as internal UT in lieu of visual piping inspections.

9. In regard to alternative inspection methods:

   a. Specifically state what alternative inspection methods beyond ultrasonic examinations or pressure testing will be utilized when excavated direct visual examinations are not possible due to plant configuration.

   b. If alternative methods beyond ultrasonic examinations or pressure testing will be utilized when not excavating and visually inspecting a buried piping segment, state why they will be effective at providing reasonable assurance that the buried in-scope piping systems will meet their current licensing basis function.

   c. State what percentage of interior axial length of the pipe will be inspected and the frequency of testing. If the alternative inspection methods cover less than 25 percent of the linear feet of piping for the material type, or the frequency exceeds five years, state why the method provides reasonable assurance that the piping will meet its current licensing basis function.

Response: PNPS is not using alternative inspection methods on this in-scope piping.

Low-Voltage Cables

Background

NUREG-1801, Rev. 1, "Generic Aging Lessons Learned," (the GALL Report) addresses inaccessible medium voltage cables in Aging Management Program (AMP) XI.E3, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" (Inaccessible Cables Program). The purpose of this program is to provide reasonable assurance that the intended functions of inaccessible medium voltage cables (2 kV to 35 kV), that are not subject to environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by moisture while energized, will be maintained consistent with the current licensing basis. The scope of the program applies to inaccessible (in conduits, cable trenches, cable troughs, duct banks, underground vaults or direct buried installations) medium-voltage cables within the scope of license renewal that are subject to significant moisture simultaneously with significant voltage (energized 25% of the time).

The application of the Inaccessible Cables Program to medium voltage cables was based on the operating experience available at the time revision 1 of the GALL Report was developed. However, industry operating experience subsequent to GALL Report, revision 1, (i.e., during the time period from 2004 to 2009) indicates that the presence of water or moisture can be a contributing factor in inaccessible power cables failures at lower service voltages (400 V to 2 kV). Applicable operating experience was identified in licensee responses to Generic Letter (GL) 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," which included failures of power cable operating at service voltages of less than 2 kV where water was considered a contributing factor. The staff also noted that the *significant voltage* screening criterion (cables subject to system voltage for more than 25 percent of the time) was not applicable for all the inaccessible power cable failures noted.

Industry operating experience provided by NRC licensees in response to GL 2007-01 has shown that there is an increasing trend of cable failures with length in service and that the presence of water/moisture or submerged conditions appears to be the predominant factor contributing to cable failure. The staff has determined, based on the review of the cable failure data, that an annual inspection of manholes and a cable test frequency of at least every 6 years (with evaluation of inspection results to determine the need for an increased inspection frequency) is a conservative approach to ensuring the operability of power cables and, therefore, should be considered.

In addition, the industry operating experience referred to above has shown that some NRC licensees may experience cable manhole water intrusion events, such as flooding or heavy rain, that subject cables within the scope of the Inaccessible Cables Program to significant moisture. The staff has determined that event driven inspections of cable manholes, in addition to a 1 year periodic inspection frequency, is a conservative approach and, therefore, should be considered.

Issue

The staff has concluded, based on industry operating experience concerning the failure of inaccessible low voltage power cables (400 V to 2 kV) in the presence of significant moisture, that these cables can potentially experience age related degradation. In addition, more frequent cable test and cable manhole inspection frequencies (e.g., from ten and two years to six and one year, respectively) should be evaluated to ensure that the Inaccessible Cable Program test and inspection frequencies reflect industry and plant-specific operating experience. Further, cable test and manhole or vault inspection frequencies may be increased based on future industry and plant-specific operating experience. Further, the staff has concluded that the removal of the *significant voltage* criterion is also a conservative approach and therefore should also be considered.

By letter dated January 7, 2011, the applicant submitted supplemental information to the LRA to address aging management of low voltage cables. The staff has reviewed the LRA supplement and has noted that the LRA supplement does not address the staff's concerns regarding inaccessible power cables or is incomplete in the areas identified below.

Request

1. The "operating experience" section discussion (Attachment 1, page 8) states that the applicant reported no failures of medium voltage or low voltage inaccessible cables during the GL 2007-01 review. The LRA supplement also states that since the applicant's response to GL 2007-01, PNPS operating experience was researched through the corrective action program and no failures were found for inaccessible 400 to 2kV cables. Provide additional discussion on plant specific operating experience of inaccessible medium voltage cables subsequent to your response to GL 2007-01.

   Response: PNPS operating experience since the response to GL 2007-01 was researched through the corrective action program and no failures were found for inaccessible medium voltage cables.

   Explain why the operating experience discussion shown in Attachment 1, page 8 is not included in the LRA, Section B.1.19 "operating experience" discussion (Attachment 1, Page 10).

   Response: RAI responses are amendments to the License Renewal Application. Therefore, the operating experience discussion in the PNPS letter dated January 7, 2011, Attachment 1, page 8 is included in the LRA.

2. The "discussion" section (Attachment 1, page 8) does not include a discussion on adding event driven inspections (rain or flood) or the elimination of the *significant voltage* criterion. Explain why event driven inspections and the elimination of the *significant voltage* criterion are not included in the "discussion" section of Attachment 1, page 8.

   Response: The program description on Page 9 addresses operational inspections performed to verify drainage systems are functional prior to predicted heavy rains or flooding events such as hurricanes. The program description on Page 9 also reflects the elimination of significant voltage as a criterion for cables in the program.

3. The LRA, Section A.2.1.21, "Non-EQ Inaccessible Medium-Voltage Cable Program," (Attachment 1, page 8) does not include a discussion of event driven inspections (rain or flood) or a discussion of the evaluation of test results used to determine the need for increased cable test frequencies. Explain why event driven inspections or the use of cable test results to determine the need for increased test frequencies are not discussed in LRA Section A.2.1.21.

Response: Revised Commitment #15 specifies event-driven inspections and includes the provisions for evaluation of test results to determine the need for increased test frequency. LRA Section A.2.1.21 is revised to read as follows.

In the Non-EQ Inaccessible Medium-Voltage Cable Program, in-scope cables (400V to 35 kV) exposed to significant moisture will be tested at least once every six years to provide an indication of the condition of the conductor insulation. Significant moisture is defined as periodic exposures that last more than a few days. The specific test performed is a proven commercially available test for detecting deterioration of the insulation system due to wetting. Test frequencies are adjusted based on test results (including trending of degradation where applicable) and operating experience.

Inspections for water collection in cable manholes and conduit containing inaccessible power cables in scope of this program will occur at least annually, with some manholes inspected more frequently based on evaluation of inspection results. PNPS will verify dewatering system function prior to and after heavy rain or flooding events. The PNPS operating procedure for coastal storms will be revised before the PEO to stipulate assessment of manhole dewatering systems prior to a storm, and stipulate manhole inspections thereafter.

4. The LRA, Section B.1.19, "Non-EQ Inaccessible Medium Voltage Cable," (Attachment 1, page 9) states that the Non-EQ Inaccessible Medium-Voltage Cable Program will be based on and consistent with NUREG-1801, Revision 2, Section XI.E3. However, the LRA, Section B.1.19 does not describe inaccessible medium voltage cables or the addition of low voltage inaccessible power cables (400V to 2kV). Explain why medium voltage and low voltage inaccessible power cables are not described (i.e., 400V to 35kV) in LRA Section B.1.19.

   Response: LRA, Section B.1.19 (Entergy Letter, 2.11.001, Attachment 1, Page 9) states "Inspections for water accumulation in manholes containing inaccessible low- and medium-voltage cables with a license renewal intended function will be conducted..." and "In-scope low-voltage and medium-voltage cables exposed to significant moisture will be tested at least once every six years...". Section B.1.19 also states "The program attributes of the Non-EQ Inaccessible Medium-Voltage Cable Program at PNPS will be consistent with the program attributes described in NUREG-1801, Revision 2, Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." NUREG-1801, Revision 2, Section XI.E3 defines the voltage range of cables in this aging management program. In addition, LRA Section A.2.1.21 defines the applicable voltage range for cables in the program as 400V to 35kV. PNPS has no inaccessible power cables with a license renewal intended function with an operating voltage above 35kV.

5. LRA Section B.1.19, "Non-EQ Inaccessible Medium Voltage Cable," (Attachment 1, page 9) states that additional operational inspections will be performed to verify drainage systems are functional prior to predicted heavy rains or flooding events such as hurricanes.

   Although operational inspections are stated to be performed prior to predicted heavy rains or flooding events it is not clear to the staff that all in-scope manholes are equipped with dewatering/drainage systems such as sump pumps. Confirm that all in-scope manholes are equipped with dewatering/systems such as sump pumps.

If in-scope manholes are not equipped with dewatering/drainage systems, explain how these manholes are inspected for event driven occurrences (heavy rain or floods, etc.). In addition, for in-scope manholes equipped with dewatering/drainage systems, explain how these manholes are inspected subsequent to event driven occurrences to ensure that inaccessible power cables are not exposed to significant moisture.

For manholes equipped with dewatering/drainage systems such as sump pumps, provide information on surveillance and functional testing performed on these systems that ensures proin-scope inaccessible power cable.

Response: Two in-scope manholes have an automatic dewatering system. The remainder of in-scope manholes gravity drain to the level of the water table and are augmented with manual pumping based on manhole inspection results. The inspection of the manholes with the automatic dewatering system provides visual verification that the system is functioning. PNPS will ensure verification of dewatering system function prior to and after event based occurrences. The PNPS operating procedure for coastal storms will be revised before the PEO to stipulate assessment of manhole dewatering systems prior to a storm, and stipulate manhole inspections following the storm.

6. LRA Section B.1.19, "Non-EQ Inaccessible Medium Voltage Cable," (Attachment 1, page 9) states that in-scope medium and low-voltage cables exposed to significant moisture will be tested once every 6 years. LRA Section B.1.19 also states that all in-scope medium-voltage cables will be tested prior to entering the period of extended operation (PEO) and that low-voltage cables will be tested within six years of entering the PEO.

   Explain how the testing frequency for medium and low-voltage inaccessible power cable is consistent with the GALL Report, since the GALL Report states that the *first tests for license renewal are to be completed prior to PEO* with subsequent tests performed at least every 6 years thereafter.

   Response: The LRA was submitted and reviewed while Revision 1 of the GALL report was in effect. Revision 1 of the GALL report did not include low-voltage cables in a program for testing inaccessible power cables. The NRC staff issued Revision 2 of the GALL report in December 2010. PNPS will test low-voltage inaccessible power cables that support a License Renewal function prior to the PEO. The timing of the first testing and the frequency are consistent with the recommendations of Revision 2 of the GALL report.

7. LRA Section B.1.19, "Non-EQ Inaccessible Medium Voltage Cable," (Attachment 1, page 9) does not indicate that inaccessible power cable test results may be used to adjust test frequencies based on test results.

   GALL Report Revision 2, AMP X1.E3 states that for power cables exposed to significant moisture, test frequencies are adjusted based on test results. Explain why the provision to include cable test results used to determine the need for increased test frequencies are not part of LRA Section B.1.19.

Response: The provision to evaluate cable test results to determine the need for increased test frequencies is included in Commitment 15. LRA Section B.1.19 and the commitment taken together define the necessary attributes of the program ensuring that this provision is implemented in accordance with the commitment.

8. LRA Section B.1.19 does not include a definition for "significant moisture." LRA Section A.2.1.21 includes the definition. Explain why LRA Section B.1.19 does not include a definition for significant moisture.

   Response: LRA Section B.1.19, "Non-EQ Inaccessible Medium Voltage Cable," (Entergy Letter, 2.11.001, Attachment 1, Page 9) incorporates by reference GALL Report Revision 2, AMP XI.E3, which defines significant moisture. In addition, LRA Section A.2.1.21 defines significant moisture.

9. Commitment No.15 (Attachment 2, page 2) states that inaccessible cables will be tested for cable insulation degradation at least once every 6 years after entering the period of extended operation.

   Explain how the testing frequency for medium and low-voltage inaccessible cable is consistent with the GALL Report Revision 2, AMP XI.E3 that states the first tests for license renewal are to be completed prior to PEO with subsequent tests performed at least every 6 years thereafter.

   Response: Medium- and low-voltage power cables will be tested prior to the PEO, and at least once every six years after entering the PEO.

Protective Containment Coatings

Program Description

The Protective Coating Monitoring and Maintenance Program at PNPS is a new program that will be consistent with the program described in NUREG-1801, Section XI.S8, Protective Coating Monitoring and Maintenance Program.

The Protective Coating Monitoring and Maintenance Program manage the effects of aging on Service Level I coatings. Service Level I protective coatings are not credited to manage the effects of aging, however, proper maintenance of protective coatings inside containment is essential to ensure operability of post-accident safety systems that rely on water recycled through the containment. Proper monitoring and maintenance of Level I coatings ensures there is no coating degradation that would impact safety functions. The PNPS Protective Coatings Monitoring and Maintenance Program will comply with those sections of RG 1.54 Revision 2 that relate to managing the effects of aging, that is, inspection and maintenance of Service Level I protective coatings as addressed under Section C.3 "Training and Qualifications of Nuclear Coating Specialist, Protective Coating Inspectors and Coating Applicators" and Section C.4 "Maintenance of Coating." RG 1.54 endorses ASTM D5163-08 as acceptable guidance for establishing an in-service coating monitoring program for Service Level I coating systems in operating nuclear power plants.

Evaluation and Technical Basis

1. *Scope of Program:* The Protective Coatings Monitoring and Maintenance Program manages the effects of aging on Service Level I coatings applied to steel and concrete surfaces inside containment (e.g., steel containment shell, structural steel, supports, penetrations, and concrete walls and floors). The PNPS program is the same program described in the 10-element program description of NUREG-1801 Section XI.S8. The PNPS program will comply with the guidelines identified in ASTM D5163-08 for specifics of an acceptable aging management program for Service Level I coatings.

2. *Preventive Action:* The program is a condition monitoring program and does not include preventive actions.

3. *Parameters Monitored or Inspected:*
In accordance with ASTM D5163, Section 10.0, parameters monitored or inspected are "any visible defects, such as blistering, cracking, flaking, peeling, rusting, and physical damage."

4. *Detection of Aging Effects:* Coating condition assessment does take into consideration a review of documentation regarding the prior as-found condition. The coatings assessment program will be coordinated with existing inspection programs and maintenance activities. The containment (ASME-IWE) inspection, for example, includes inspection of the coating when assessing the wall thickness of the steel containment. Coating inspections will be performed at least once every 40 months in conjunction with the IWE program.

A general visual inspection will be conducted on all readily accessible coated surfaces during each refueling outage. After the general visual inspection, a thorough visual inspection will be carried out on previously designated areas and on areas noted as deficient. Inspectors will perform a thorough visual inspection on all coatings near sumps or screens associated with the emergency core cooling system (ECCS). Field documentation of inspection results will be performed in accordance with subparagraph 10.3 of ASTM D5163-08. If portions of the coating cannot be inspected, the inspector will note the specific areas on the location map-inspection report, along with the reason why the inspection cannot be conducted. For coating surfaces determined to be suspect, defective, or deficient, physical tests, such as dry film thickness (Test Methods D1186 and SSPC-PA 2), and adhesion (Test Methods D3359, D4541, or D6677) may be performed when directed by the Nuclear Coating Specialist. ASTM D 5163, subparagraph 10.5, identifies instruments and equipment that may be needed for inspection.

Although the ASTM D5163 standard provides reasonable assurance that qualified coatings left in service after a visual inspection will remain adhered to their substrates under accident conditions, it does not guarantee that visual inspection will detect all degraded coatings. Therefore, PNPS included margin in debris-generation calculations for ECCS strainer performance (Ref: Pilgrim 120 Day Response to GL 98-04 Concerning Containment Coatings, Construction, and foreign Material Issues; letter #2.98.141, dated November 23, 1998).

In accordance with the recommendations of NUREG-1801, Section XI.S8,

a) Personnel qualification will be in accordance with paragraph 9 of ASTM D 5163.

b) Individuals who perform visual assessment and coordinate coating condition assessment shall be nuclear coating specialists per D7108-05 or personnel judged acceptable by a nuclear coating specialist. A PNPS nuclear coating specialist shall meet one of the combinations of qualification attributes provided in Table 2 of ASTM D7108. Follow-up inspections, if needed, shall be by individuals trained in the applicable referenced standards of Guide D5498 and meet the requirements of the PNPS Quality Assurance Program.

5. ***Monitoring and Trending:*** Consistent with ASTM D5163 subparagraph 7.2, prior to beginning the inspection, inspectors will review the previous two inspection reports.

6. ***Acceptance Criteria:*** ASTM D5163, paragraph 11, addresses evaluation and documentation. The inspection report is to be evaluated by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, and prioritization of repairs. The evaluation covers blistering, cracking, flaking, peeling, delamination, and rusting. ASTM D5163, subparagraphs 10.2.1 through 10.2.6, 10.3, and 10.4, provide guidance for the characterization, documentation, and testing of defective or deficient coating surfaces. In conjunction with ASTM D5163, the following ASTM standards will be used in the aging management program in addition to those ASTM standards listed in D5163, Step 2 "Referenced Documents."

- ASTM D660 for evidence of checking
- ASTM D661 for evidence of cracking
- ASTM D772 for evidence of flaking (scaling)

Additional ASTM standards, which will be used as necessary should degradation be found, are the following.

- ASTM D7091-05, "Standard Practice for Nondestructive Measurement of Dry Film Thickness of Nonmagnetic Coatings Applied to Ferrous Metals and Nonmagnetic, Nonconductive Coatings Applied to Non-Ferrous Metals"
- ASTM D3359, "Test Methods for Measuring Adhesion by Tape Test"
- ASTM D3363, "Standard Test Method for Film Hardness by Pencil Test"

- ASTM D4541, "Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers"
- ASTM D4787, "Practice for Continuity Verification of Liquid or Sheer Linings Applied to Concrete Substrates"
- ASTM D5162, "Standard Practice for Discontinuity (Holiday) Testing of Nondestructive Protective Coatings on Metallic Substrates"
- ASTM D6677, "Standard Test Method for Adhesion Testing by Knife"
- ASTM D7234, "Standard Test Method for Pull-Off Adhesion Strength of Coatings on Concrete Using Portable Pull-Off Adhesion Testers"

7. *Corrective Actions:* A recommended corrective action plan is specified for major defective areas so that these areas can be repaired during the same outage, if appropriate. In accordance with subparagraph 11.1.2, repairs will prioritize areas as either needing repair during the same outage or as acceptable for service until future outages, with appropriate surveillance in the interim. The requirements of the PNPS (10 CFR Part 50, Appendix B) Quality Assurance Program address corrective actions under this program.

8. *Confirmation Process:* The requirements of the PNPS (10 CFR Part 50, Appendix B) Quality Assurance Program address the confirmation process.

9. *Administrative Controls:* The requirements of the PNPS (10 CFR Part 50, Appendix B) Quality Assurance Program address administrative controls.

10. *Operating Experience*: While the PNPS Protective Coating Monitoring and Maintenance Program is a new program, containment coatings have been subject to routine inspection in accordance with Pilgrim procedures and inspection checklists associated with other programs. Anomalies are identified, compared to previous inspections and established criteria, and where appropriate, entered into the Corrective Action Program. Coating inspections were conducted and documented in conjunction with the IWE containment examinations in 1999, 2003, and 2007; and are scheduled for 2011. Torus desludging, coating inspection and coating repair was performed by divers in 1999, 2003, and 2007. Results have determined assessments continue to be bounding as volumes are less than allowed by calculation and therefore the present frequencies for examinations are adequate to manage aging effects. The Structures Monitoring Program inherently addresses protective coatings on structures and structural components inside primary containment through visual inspections of those structures and components. Industry operating experience identified in GL 98-04, and tenets of EPRI TR-109937 were used in establishment of PNPS, and Entergy Containment Coatings Program.

Conclusion

The PNPS Protective Coating Monitoring and Maintenance Program will be effective for managing aging effects of Service Level 1 coatings since it will incorporate proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls consistent with those described in NUREG 1801, Section XI.S8. The PNPS Protective Coating Monitoring and Maintenance Program provides reasonable assurance that the effects of aging on Service Level 1 coatings will be managed such that applicable system, structures and components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

Metal Fatigue NUREG/CR-6260

Reference 3 provided Pilgrim's response to Draft RAI 4.3.3-1 – Metal Fatigue NUREG/CR-6260. The following is Pilgrim's Commitment 52.

Commitment 52

Entergy is providing the following new commitment (Commitment 52) for the Metal Fatigue NUREG/CR-6260;

Entergy will review design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the Pilgrim plant configuration. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage.

PNPS will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any. This evaluation will be completed prior to the period of extended operation.

Attachment 2 to Letter No. 2.11.017

Pilgrim Nuclear Power Station
License No. DPR-35 (Docket No. 50-293)

License Renewal Application

License Renewal Commitment List

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.

ITEM	COMMITMENT	TYPE (Check one)		SCHEDULED COMPLETION DATE (If Required)
		ONE-TIME ACTION	CONTINUING COMPLIANCE	
52	Entergy will review design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the Pilgrim plant configuration. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage. PNPS will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any. This evaluation will be completed prior to the period of extended operation.	X		6/8/2012