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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board Panel

In the Matter of	)	
	)	
Entergy Nuclear Generation Company and	)	Docket No. 50-293-LR
Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

Rebuttal Testimony of Alan Cox, Brian Sullivan, Steve Woods, and William Spataro on Pilgrim Watch Contention 1, Regarding Adequacy of Aging Management Program for Buried Pipes and Tanks and Potential Need for Monitoring Wells to Supplement Program and Response to Atomic Safety and Licensing Board's Questions of February 21, 2008

TEMPLATE = SECY-055

SECY-02

March 6, 2008

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I. Response to General Programmatic Claims in Gundersen Testimony

Q1. Have you reviewed the Declaration of Arnold Gundersen Supporting Pilgrim Watch's Petition for Contention 1?

A1. (ABC, BRS, SPW, WHS) Yes.

Q2. Do you agree with Mr. Gundersen's assertion (e.g., ¶¶ 9, 11 and Conclusion) that the proposed license renewal aging management program ("AMP") for buried pipes and tanks at Pilgrim Nuclear Power Station ("PNPS"), the Buried Piping and Tanks Inspection Program ("BPTIP"), is inadequate?

A2. (ABC, BRS, SPW, WHS) No. We do not. For the reasons stated in our original testimony, we believe that the BPTIP is adequate because it manages the effects of aging in a manner providing reasonable assurance that intended functions can be accomplished as required by the NRC's license renewal regulations.

Q3. Do you agree with the assertion in ¶ 9 of Mr. Gundersen's testimony that the AMP for buried piping is "vague and non-specific?"

A3. (ABC) No. First, as explained in our initial testimony, the BPTIP is very specific that a minimum of two inspections must be performed with respect to buried pipes and tanks subject to the program. See Testimony of Alan Cox, Brian Sullivan, Steve Woods, and William Spataro on Pilgrim Watch Contention 1, Regarding Adequacy of Aging Management Program Buried Pipes and Tanks and Potential Need for Monitoring Wells to Supplement Program (Jan. 8. 2008) ("PNPS Test.") at 37-38 (Q's and A's 75 and 77). (As discussed in our prior testimony, there are no buried tanks subject to this contention.) Second, as also explained in our initial testimony, the BPTIP is in conformance with NUREG 1801, Generic Aging Lessons Learned ("GALL") Report, Rev. 1 (Sept. 2005), which identifies AMPs that the NRC has determined acceptable for managing the effects of aging on systems, structures and components within the scope of license renewal. PNPS Test. at 35-36, 42-43 (Q's and A's 73 and 90).

Q4. Do you agree with the assertion in ¶ 9 of Mr. Gundersen's testimony that the AMP for buried piping "cannot be used to conclude that any and all underground piping will ever be examined during the license extension period"?

A4. (ABC) No. As I just stated, the BPTIP is very specific that a minimum of two inspections must be performed with respect to buried pipes and tanks subject to the program, and one of these inspections must occur within the first ten years after license renewal. Thus, inspection of sections of buried piping <u>must</u> occur under the BPTIP. However, there is no requirement in the GALL Report or the BPTIP that the entire length of the buried piping be examined. Nor is there any need to do so, and, in fact, the excavation that would be required to examine all underground piping poses unnecessary risk of damage to otherwise sound coatings. Rather, in accordance with the GALL Report, the BPTIP is intended to be a sampling program to assess and verify the general condition of the coating.

Q5. Do you agree with Mr. Gundersen's assertion, in ¶ 12, that Entergy has "itself recognized the inadequacy" of its AMP for buried pipes and tanks because it has developed a new procedure, "Buried Piping and Tanks Inspection and Monitoring Program"?

A5. (ABC, WHS) No. As clearly stated in our testimony, the Buried Piping and Tanks Inspection and Monitoring Program ("BPTIMP") is an implementing procedure that implements not only the BPTIP AMP inspections but additional inspections that go beyond the scope of the license renewal rule. PNPS Test. at 38-39, 42-43 (Q's and A's 78-80, 90). Development of a new procedure to accomplish objectives unrelated to managing the effects of aging for license renewal is clearly not evidence that the activities proposed to address license renewal objectives are inadequate. Entergy has simply consolidated in the same procedure, license renewal requirements along with certain other measures that are part of the Nuclear Energy Institute ("NEI") groundwater protection initiative for the convenience of the engineers who will implement these measures.

Q6. What about Mr. Gundersen's claim in ¶ 12.4.2 of his testimony that Section 5.2 of the BPTIMP, Scope of Program, subsection [3] "clearly acknowledges the validity of Pilgrim Watch's initial contention by stating that 'The program shall include buried or partially buried piping and tanks that, if degraded, could provide a path for radioactive contamination of groundwater'"?

A6. (ABC, WHS) Mr. Gundersen ignores the dual functions of the BPTIMP, just described above, which are clearly stated in Section 5.2 of the BPTIMP. Section 5.2 defines the scope of the BPTIMP and reflects the multiple functions of the BPTIMP. Subsection [2] of Section 5.2 states that the BPTIMP encompasses all buried pipes and tanks that fall within the scope of license renewal, for which it references Section XI.M34 of the GALL Report (Buried Piping and Tanks Inspection).

Subsection [3] provides that the BPTIMP shall also include buried or partially buried piping and tanks that, if degraded, could provide a pathway for radioactive contamination of groundwater, and it references the NEI groundwater protection initiative. Accordingly, as the BPTIMP addresses systems that are not even within the scope of license renewal, the procedure is plainly intended to go beyond implementing license renewal commitments.

Therefore, it is clear from an analysis of Section 5.2 that the BPTIMP does much more than ensure maintenance of the license renewal intended functions for systems within the scope of license renewal. Wholly in addition to license renewal AMP functions, the BPTIMP is also intended to implement the NEI initiative to prevent leakage and radioactive contamination of groundwater, which Entergy has voluntarily undertaken at all of its nuclear power plants. Entergy has efficiently combined the implementation of these two objectives into a single procedure.

It is true that groundwater protection is important to Entergy. That is why Entergy implements groundwater monitoring and also requires risk-based inspections of buried piping beyond the scope of the license renewal rules. But the fact that Entergy implements these measures as part of its commitment to protect the environment in no way implies that such programs are within the scope of the NRC's license renewal rules. Rather, these groundwater protection measures are current operating programs that Entergy would implement irrespective of license renewal.

Q7. In discussing the buried piping AMP, Mr. Gundersen says in paragraph 12.3 of his testimony that "[g]iven the recent tritium findings…, in my opinion the Public requires a firm commitment from Entergy Pilgrim, not simply a voluntary plan that the plant may choose to adhere to or not." Are the license renewal AMPs for buried piping voluntary?

A7. (ABC) No. The license renewal AMPs are not voluntary. They are licensing commitments made by Entergy in the license renewal application which are reflected in a supplement to the updated final safety analysis report as required by the NRC's rules. See LRA Section A.2.1.2 (provided as Entergy Exhibit 6). Further, implementation of the BPTIP is included in the NRC's safety evaluation report ("SER") as a commitment. See NUREG-1891 (Sept. 2007, Published Nov. 2007) at A-3 (commitment 1) (provided as Entergy Exhibit 7).

The BPTIMP, as discussed above, includes steps to implement a groundwater protection initiative that are unrelated to license renewal requirements. This groundwater protection initiative is a voluntary action undertaken by Entergy, but the BPTIP is not.

Q8. What bearing do the so-called "tritium findings" referred to by Mr. Gundersen in ¶ 12.3 have on the AMP?

A8. (ABC, BRS) As discussed in our testimony below, the "tritium findings" have no bearing on the AMP.

Q9. Mr. Gundersen also claims in paragraphs 12.4.6 – 12.4.6.3 of his testimony that the BPTIMP is inadequate because it does not address internal corrosion. What is your response to the criticisms made by Mr. Gundersen?

A9. (ABC, WHS) Mr. Gundersen fails to recognize that the BPTIMP and the BPTIP are intended to manage external degradation and other programs exist to manage internal degradation. The BPTIMP expressly states in Section 1.0, "PURPOSE," that "the Program consists of inspection and monitoring of selected operational buried piping and tanks <u>for external corrosion</u>." (Emphasis added.) Similarly as stated in our original testimony, the BPTIP is the AMP established to manage external degradation of buried piping. PNPS Test. at 19-20 (Q and A 35). This is in accordance with the GALL Report which specifically states that "the program relies on preventive measures such as coating, wrapping and periodic inspection for loss of material caused by corrosion of the external surface of buried steel piping." GALL Report, Section XI.M34 (emphasis added).

Other AMPs are expressly established and in place to manage the internal corrosion of buried pipes. These are the Water Chemistry Control-BWR Program, the Service Water Integrity Program, and the One-Time Inspection Program. PNPS Test. at 19-20 and 43-47 (Q's and A's 35 and 91-102).

II. Baseline Review of Entire Length of Pipe is Inapplicable and Unnecessary

Q10. In paragraph 12.4.1.1 of his testimony Mr. Gundersen asserts that the BPTIP/BPTIMP "fails in that it never requires a complete baseline review." What is a "complete baseline review"?

A10. (ABC, WHS) Mr. Gundersen does not define what he means by "a complete baseline review." With respect to in-service inspection programs, a baseline inspection typically establishes the as-installed condition of a component against which the extent of any subsequent degradation can be assessed. Since the BPTIP employs visual inspection of surface conditions, a baseline inspection would essentially be the inspection performed of the coating following initial application.

It is important, however, to recognize where such a baseline inspection is not useful. Where a corrosion rate is non-existent (e.g., where corrosion is prevented by coatings or choice of materials such as the case here) or is irregular or localized (e.g., pitting), such a baseline review does not assist in managing corrosion or predicting the integrity of the piping system.

Q11. Did PNPS perform a baseline inspection of the buried piping subject to this contention?

A11. (ABC, BRS, SPW, WHS) Yes. The installation inspections of the buried piping at PNPS serve as baseline inspections. When the buried piping was originally installed, and when the replacement piping for the salt service water ("SSW") system was installed, there was a 100% inspection of the installed components to confirm installation of the coatings and piping per specifications. Thus, there is a baseline that may be used for comparison to the as-found condition of the buried pipes in subsequent inspections.

Q12. In paragraph 18.1.5 of his testimony, Mr. Gundersen suggests that establishing baseline data is "critical so that trending is established." Do you agree?

A12. (ABC, WHS) No. Mr. Gundersen's testimony implies that PNPS should be trending a corrosion rate, but this is not the purpose of the BPTIP. Rather, the purpose of the BPTIP is to determine that the coatings are intact, which prevent corrosion from occurring, and not to measure the rate of an ongoing corrosion mechanism. As stated in our original testimony, pipe surfaces that are coated with coal tar or epoxy coatings will not corrode. Nor will the SSW discharge pipe interior surface lined with Cured in Place Piping (which forms an impervious smooth and hardened protective surface) corrode. The water in the Condensate Storage System ("CSS") buried piping (made of corrosion resistant stainless steel) is normally not subject to water flow conditions and the piping is not subject to corrosion or any other degradation mechanism that would lend itself to trending.

Thus, using baseline data to establish corrosion rate trending is meaningless – the pipe external surface has no corrosion rate as long as the coating remains intact. When dealing with coated or lined pipe, the best practice is for inspections, such as those described in the LRA, to ensure that the coatings are properly remaining in place.

Q13. In paragraph 18.1.5 of his testimony, Mr. Gundersen also refers to NUREG/CR 6876 to support his claimed need for baseline data. Does this reference support his position here?

A13. (WHS) No. The statement quoted from NUREG/CR 6876 says that, "...it is evident that predicting an accurate degradation rate for buried piping systems is difficult to achieve...." This statement, and the surrounding text, do not mention baseline data at all. Further, as discussed above, PNPS does not attempt to predict a degradation rate but implements measures (coatings and choice of materials) to prevent degradation from occurring.

III. Response to Gundersen's related claims Regarding Key Specific Components

Q14. In paragraph 12.4.3 of his testimony, Mr. Gundersen lists the types of information and data that he claims the BPTIMP should require to be collected for inspection of the buried piping. What is your response to Mr. Gundersen's claims?

A14. (ABC, SPW, WHS) At the outset, Mr. Gundersen's claims are based on the same misunderstanding, discussed above, concerning the scope and purpose of the inspections under BPTIP AMP, which the BPTIMP supports. The ten specific criteria suggested by Mr. Gundersen are largely irrelevant to the stated objective of inspections under the BPTIP, which is to determine whether the protective coating on the buried piping remains in place. For example, there is no apparent reason why knowing the manufacturer's warranty would have any bearing on whether a coating is intact. Some of the items mentioned by Mr. Gundersen might be relevant if damage or degradation to the coating is found, but that would depend on the type and extent of the problem. In such case, the information needed to assess any non-conforming condition is readily available at the plant.

Furthermore, the BPTIMP already requires the program owner to "collect physical drawings, piping/tank installation specifications, piping design tables, and other data needed to support inspection activities." Section 5.4 [1]. This instruction is sufficient to require the collection of pertinent data needed for the inspections. Additionally, the BPTIMP includes an Attachment 9.4 that provides a detailed list of data that is to be collected for inspection under the BPTIMP.

Q15. Please identify those categories of information that Mr. Gundersen claims are missing from the BPTIMP that are actually called for by the BPTIMP.

A15. (WHS, SPW) Mr. Gundersen claims that the wall thickness and cathodic protection of the buried piping should be specified, but both are already part of the information required by Attachment 9.4 (although the components within the scope of Pilgrim Watch's contention do not employ cathodic protection). The "last inspection date and report number" is also already required. BPTIMP §5.11[3] ("the Program Owner shall document all inspection testing and analysis results and any engineering evaluations performed, in an Engineering Report... The Program Owner shall maintain the record of all inspection results in an Engineering Report.")

Section 5.4[3] requires PNPS to collect data regarding the most critical factors affecting the external corrosion of buried piping, negatively or positively. The coating on the piping exterior surface is listed as one of the factors. See BPTIMP Attachment 9.4. Such coating is essentially uniform and its performance is not affected by the presence of underlying welds, elbows, or blank flanges. Further, there are no blank flanges in the CSS or SSW buried pipe. Therefore, documenting these criteria is irrelevant in determining whether the coatings remain in place, which is the stated programmatic objective of the BPTIP AMP.

Q16. What is your response to other categories of information that Mr. Gundersen claims are missing from the BPTIMP?

A16. (WPS, SPW) As stated, the presence of underlying welds, elbows, or blank flanges are irrelevant in determining whether the coatings remain in place. Furthermore, several of Mr. Gundersen's criteria, such as flow restrictions, high velocity portions, dead spaces, or flow disturbances, concern internal corrosion and not external corrosion, which is the subject of the inspections under the BPTIP credited for license renewal. Moreover, these criteria are not relevant to the CSS and SSW system buried piping. There are no flow restrictions, high velocity portions, dead-space or flow disturbances in the buried CSS and SSW system piping. Indeed, there is no flow in the CSS system buried piping during normal plant operation except during quarterly surveillance and other periodic testing of the capability of the HPCI and RCIC systems.

Manufacturers warranties are not a relied upon variable for any buried piping engineering justification at PNPS. The age of in-scope buried pipes is also irrelevant. Metals do not simply "age," but instead, if unprotected and susceptible, may degrade at varying rates as a result of electrochemical, thermal, or mechanical conditions. As stated in our original testimony, PNPS takes precautions to prevent such degradation from occurring. For example, the SSW inlet pipe is titanium and is corrosion resistant; the SSW outlet piping is carbon steel coated externally with a coal-tar or an epoxy coating and internally with a cured in place lining, both of which function to prevent corrosion. The CSS buried piping is made of corrosion resistant stainless steel and, in accordance with PNPS specifications, is coated. Moreover, the ages of the buried piping is clearly known from the original installation and replacement records for the CSS and SSW system.

IV. Frequency and Breadth of Buried Pipe Inspections

Q17. Do you agree with Mr. Gundersen's assertion in paragraph 12.4.5.1 of his testimony that the time interval between inspections proposed for the BPTIP is "too long"?

A17. (ABC, WHS) No. At the outset, in paragraph 12.4.5 of his testimony (as well as in other portions of his testimony), Mr. Gundersen challenges the inspection provisions of the BPTIMP. However, as discussed above and in our original testimony, the BPTIMP has a dual function and provides for inspections of buried pipes that are above and beyond those required for license renewal under the BPTIP. The BPTIP is very specific on the number and purpose of those inspections required for license renewal, and based on industry experience, those inspections are sufficient to satisfy the aging management functions of the LRA.

Under the BPTIP, PNPS inspects – at a minimum – in-scope buried piping within ten years of license renewal and within ten years after license renewal. As discussed in our original testimony, based on industry and PNPS experience of coated buried piping, such inspections are sufficient to provide reasonable assurance of the continued integrity of the buried piping systems at PNPS to perform their intended functions during the period of extended operation. PNPS Test. at 37-38 (Q and A 77). This experience demonstrates that coatings remain in good condition after many years of service and that coated materials are not expected to degrade with exposure to PNPS soil environment. Coupled with ongoing operational monitoring, inspection of accessible areas of buried piping at the specified frequency is adequate to assure intended functions can be maintained – which is the purpose of the LRA AMPs. We see nothing in Mr. Gundersen's testimony that contradicts this industry experience or suggests otherwise.

Furthermore, it should be noted that because the current operating license for Pilgrim expires in 2012, the in-scope buried piping must be inspected in the next four years, and then at least once more in the 10-year interval after license renewal. Further, the LRA BPTIP also requires opportunistic inspections any time buried piping is excavated. In addition, if conditions adverse to quality were detected by these inspections, corrective action would be required, which would include increased inspection frequency, if needed, to establish the effectiveness of the corrective action.

Q18. Mr. Gundersen claims in paragraph 12.4.5.4 of his testimony that "absent from this procedure is the prudent and practical guidance to conduct the inspection provisions of this procedure when opportunities present themselves, regardless of the inspection intervals." Is Mr. Gundersen's characterization of opportunistic inspections correct?

A18. (ABC) No. The BPTIP AMP described in LRA Section B.1.2 expressly states, "buried components are inspected when excavated during maintenance." (Emphasis added.) Furthermore, the GALL Report, AMP XI.M34, expressly provides that "buried piping and tanks are opportunistically inspected whenever they are excavated during maintenance." GALL Report § XI.M34. The BPTIP takes no exception to this provision of the GALL Report AMP. LRA, Appendix B, Section B.1.2. Therefore, buried piping must be opportunistically inspected whenever excavated during maintenance as part of the LRA BPTIP.

The BPTIMP, which implements license renewal commitments of the BPTIP, states in Section 13.0 that, "each plant site must ensure that it complies with the commitments" made in its LRA. Furthermore, the BPTIMP expressly states that, "each Program Owner shall evaluate the site excavating procedures/processes to take advantage of opportunistic inspections." Section 5.1 [3]

Thus, both the BPTIP and the BPTIMP expressly provide for opportunistic inspections of buried piping.

Q19. In his testimony (e.g., at paragraphs 12.4.1.2 and 12.4.1.3), Mr. Gundersen claims that inspection of the entire length of a buried component is necessary. Do you agree with Mr. Gundersen's assertion?

A19. (ABC, WHS) No. We do not. As stated in our testimony, the purpose of inspection is to ensure, through a sample, that coatings are not degrading. Because the coatings are applied uniformly, their characteristics should be the same at any location, and furthermore, because the piping is buried in engineered fill above the water table, there is no reason to expect significant variation in the environmental conditions to which the piping coatings will be exposed. Thus, under this program, we will look at representative samples of coatings. One does not need to examine the entire length of the pipe to ensure that the coatings are remaining in place as expected. In fact, examining the entire length of the piping introduces, during excavation with power equipment, significant unnecessary risk of damage to otherwise sound coatings.

Q20. Do you agree with Mr. Gundersen claim in paragraph 12.4.5.6 of his testimony that "ease of access to inspection point" should not be considered in determining the location to inspect?

A20. (ABC, WHS) No. Ease of access is an appropriate consideration to be evaluated along with other considerations. Under the BPTIP focused inspections are to be performed in the areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems. See the GALL Report, § XI.M34. Similarly, when opportunistic inspections are undertaken, within that part of the piping made accessible, the inspections are to be performed in those areas with the highest likelihood of corrosion problems and where there is a history of corrosion problems. Id. However, within these most susceptible areas, ease of access is an appropriate consideration. Proper access not only promotes the effectiveness of the inspections by ensuring that the components can be properly observed and instruments brought to bear, but is also important for personnel safety considerations. Absent significant differences in the underground environment, the condition of coatings on readily accessible piping should be indicative of the condition of coatings on other sections of piping exposed to the same environment.

Q21. Mr. Gundersen states in paragraph 12.4.5.3 of his testimony that in the BPTIMP "there is no requirement to shorten a subsequent inspection based upon the degree of corrosion discovered at the time of the prior inspection." Do you agree?

A21. (ABC, WHS) No. At the outset, Mr. Gundersen misreads the BPTIMP. Section 5.5[6] of the BPTIMP procedure clearly states that "prioritization of the inspections should be based on severity of the condition, risk implication and whether an immediate repair would be required. Following any inspection, the as-found condition shall be applied to the prioritization standards and determination made of next re-inspection requirement."

More importantly, and more relevant, the LRA BPTIP AMP is subject the PNPS Appendix B corrective action program ("CAP"), as described more fully below. The CAP requires evaluation of conditions adverse to quality, including assessment of necessary corrective actions. If warranted by the evaluation, the corrective action undertaken would include expanded scope or increased frequency of inspections.

Q22. According to Mr. Gundersen, a "delay" of as much as "9-months" (paragraph 12.4.4.2) can occur before an inspection after the issuance of the BPTIMP procedure. Of what relevance is this claim to the license renewal BPTIP AMP?

A22. (ABC) It is of no relevance whatsoever. As a general matter, license renewal AMPs are to be in place to manage the effects of aging during the period of extended operation, not to manage aging (or to protect groundwater) prior to license renewal. In terms of aging management inspections, the BPTIP AMP expressly requires that one inspection occur in the ten-year period prior to entering the period of extended operation. Because the Pilgrim license expires in 2012, this means that we must conduct the initial inspections in the next four years. There is no requirement in the GALL report or the BPTIP to perform an inspection immediately or within any nine month interval.

V. Corrective Action Program

Q23. Do you agree with Mr. Gundersen's claims in his testimony (e.g., paragraphs 12.4.7-12.4.10, 12.5) regarding the acceptability of the acceptance criteria and corrective action requirements in place for the inspection of buried pipes and tanks?

A23. (ABC) No. Mr. Gundersen's claims reflect a misreading of the BPTIMP procedure and a fundamental misunderstanding of the corrective action program described in Appendix B of the LRA.

Q24. Please elaborate on your answer to question 23.

A24. (ABC) The LRA expressly specifies the applicability of Pilgrim's Appendix B Corrective Action Program ("CAP") to all of the AMPs, including the BPTIP AMP. Appendix B.0.3 of the LRA (provided as Entergy Exhibit 8) states in this respect as follows:

> PNPS quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. Conditions adverse to quality, such as failures, malfunctions, deviations, defective material and equipment, and nonconformances, are promptly identified and corrected. In the

> case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the nonconformance is determined and that corrective action is taken to preclude recurrence. In addition, the root cause of the significant condition adverse to quality and the corrective action implemented are documented and reported to appropriate levels of management.

Appendix B.0.3 goes on to state:

> Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished per the existing PNPS corrective action program and document control program. The confirmation process is part of the corrective action program and includes
>
> - reviews to assure that proposed actions are adequate,
> - 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. The corrective action program constitutes the confirmation process for aging management programs and activities.

Thus, the full panoply of the PNPS corrective action program applies to PNPS aging management programs and activities.

Q25. Mr. Gundersen claims in paragraph 12.4.7 of his testimony that the acceptance criteria for the degradation of external buried pipe surfaces in Section 5.7 of the BPTIMP are vague. Do you agree?

A25. (ABC, WHS) No. Section 5.7 of the BPTIMP entitled "Acceptance Criteria" states that "acceptance criteria for any degradation of external coating, wrapping and pipe wall or tank plate thickness should be based on current plant procedures," and if not covered under current plant procedures, "new acceptance criteria should be developed based on applicable code and industry requirements."

For buried CSS and SSW system piping, the PNPS LRA BPTIP provides the applicable acceptance criteria. The BPTIP states that it is consistent with the requirements of GALL Report, Section XI.M34, for buried piping and tanks. In turn, the GALL Report expressly provides the acceptance criteria for buried pipe aging management programs as follows:

> **3.** ***Parameters Monitored/Inspected***: ...Any evidence of damaged wrapping or coating defects, such as coating perforation, holidays, or other damage, is an indicator of possible corrosion damage to the external surface of piping and tanks.
>
> * * * * * *
>
> **6.** ***Acceptance Criteria***: Any coating and wrapping degradations are reported and evaluated according to site corrective action procedures.

GALL Report at XI M-112 (Entergy Exhibit 4) (emphasis in original).

Thus, acceptance criteria are expressly provided for the inspection of buried pipes under the BPTIP AMP. Any coating and wrapping degradation is to be reported and evaluated according to the site corrective action procedures described above.

Q26. In paragraph 12.4.9 of his testimony, Mr. Gundersen claims that the inspection methods and techniques described in Section 5.12 of the BPTIMP are inadequate because they do not provide acceptance criteria that could trigger a condition report. Do you agree?

A26. (ABC, WHS) No. As Mr. Gundersen acknowledges, the title of Section 5.12 is "Inspection Methods and Technologies/Techniques." Consistent with the section's title, Section 5.12 discusses the specific inspection methods and techniques to be used for the inspection of buried pipes. Therefore, one should not find it surprising that the steps in this Section describe the methods and techniques rather than the acceptance criteria.

The acceptance criteria are provided in Section 5.7 of the BPTIMP, discussed above.

Thus, Mr. Gundersen's repeated claims in paragraph 12.4.9 of his testimony that, as long as the inspection described in Section 5.12 of the BPTIMP is conducted, the acceptance criterion is satisfied and no condition report is required whether or not damage is uncovered is simply wrong. Under the BPTIP AMP, <u>any</u> coating and wrapping degradation identified by these inspections is to be reported in a condition report and evaluated under the PNPS corrective action procedures described above.

Q27. In paragraph 12.4.8 of his testimony, Mr. Gundersen criticizes the corrective actions provided for in Section 5.8 of the BPTIMP - , for example, the information to be provided in condition reports and the methods for reviewing, evaluating and dispositioning of condition reports. Are Mr. Gundersen's criticisms valid?

A27. (ABC) No. Condition reports are developed, reviewed and processed in accordance with the CAP as discussed in the LRA and Entergy's procedure for the "Corrective Action Process," EN-LI-102. As stated above, the corrective action process is established under the PNPS quality assurance program and provides a structured process to ensure appropriate identification of any deficiency, appropriate reviews of proposed corrective actions to ensure the adequacy of the proposed actions, and the tracking and reporting of open corrective actions.

Under Entergy's corrective action procedure, EN-LI-102, the condition description and any supporting documentation must be sufficiently detailed to provide a clear understanding of the condition. Different levels of management are responsible for proper identification and the development and implementation of adequate responses to identified condition reports. Furthermore, a special management group is responsible for reviewing condition reports, classifying, categorizing, and assigning responsibility, and approving closure of conditions reports.

In short, all of the criticisms raised by Mr. Gundersen in paragraph 12.4.8 of his testimony are addressed and fall within the scope of the PNPS corrective action program, which the LRA makes applicable to all AMPs, including the BPTIP.

Q28. In paragraph 12.4.8.2 of his testimony, Mr. Gundersen asks, "Whatever happened to the concept that this Program would consist of layers of supervision so that the NRC would play some sort of oversight role in this program?" Please comment on Mr. Gundersen's question.

A28. (ABC, BRS, SPW) Mr. Gundersen does not indicate any source for his cited concept that this Program would consist of layers of supervision, and it is unclear how a program consisting of "layers of supervision" has any relationship to NRC's oversight role. However, regarding the concept of NRC oversight, nothing has "happened to" it. NRC inspectors are onsite on an ongoing basis and are free to perform any oversight of power plant operations, including buried piping inspections. Furthermore, the NRC inspectors have ready access to the corrective action reporting system, which includes condition reports. Corrective action plans are available to NRC inspectors for any desired level of oversight.

Q29. Mr. Gundersen claims in paragraph 12.5 of his testimony that "[m]ost revealing of all Entergy's proposed Program contains no provision for root cause analysis of any identified degradations." Is Mr. Gundersen's claim correct?

A29. (ABC) No. As discussed above, root cause analysis is an element of the CAP made applicable to the LRA AMPs by LRA Appendix B.0.3. This provision of the LRA expressly requires that "for any significant condition adverse to quality, measures are implemented to ensure the cause of the nonconformance is determined and that corrective action is taken to prevent recurrence. All significant conditions are subjected to an evaluation to determine root cause."

Likewise, Mr. Gundersen's concern expressed in paragraph 12.5 of his testimony that each failure will be treated as an isolated situation is also incorrect. The corrective action program groups non-significant adverse conditions by common factors such as cause. This adverse trend grouping is a tool used to address repetitive non-significant adverse conditions prior to their escalation to a significant event. This trending of repeat occurrences is an integral part of the correction action program such that each condition is not treated as an isolated situation.

VI. Other Issues Raised by Mr. Gundersen

Q30. Mr. Gundersen suggests in his testimony (e.g. ¶¶ 17.3.3 and 17.3.4) that degraded buried pipes may not be able to withstand the stresses imposed under earthquake conditions. Is this a valid concern?

A30. (BRS) No. At the outset, the purpose of the BPTIP and the AMPs is to manage the aging of buried piping in a manner so as to provide reasonable assurance that the intended function will be maintained "consistent with the current licensing basis." Therefore, one must examine the current licensing basis to determine whether there are seismic design requirements applicable to the buried piping in question. As a general matter, buried piping is not subject to significant seismic stress because the encasement of the buried piping in compacted soil serves as an energy dampener.

The condensate storage tanks ("CSTs"), which provide the source of water for the buried CSS piping, are not seismically qualified. Thus, the CSTs are not relied upon at all to respond to a seismic event. For the same reason, there is no need for the CSS buried piping to be able to withstand earthquake ground motion.

With respect to the SSW system buried piping, such piping would experience significant seismic stress only if anchored to the intake structure and the reactor building auxiliary bay. For this reason, the SSW system piping is equipped with elastomer expansion joints between the buried piping and the structures which prevent the buried piping from being affected by the seismic motion of the structures. Consequently, in the current licensing basis for the SSW discharge piping, the seismic stress is considered secondary and does not control the design.

Q31. What about Mr. Gundersen's related suggestion in paragraph 11 of his testimony that the buried piping will not be able to withstand the "stresses of an additional 20-year license extension."

A31. (BRS) Mr. Gundersen does not attempt to define the "stresses of an additional 20-year license extension." Stresses during the period of extended operation are the same as those during the initial license term. The license renewal aging management programs are intended to maintain the condition of buried piping systems such that they can continue to perform their intended functions.

Q32. Do you agree with Mr. Gundersen's claim in paragraph 17.1.4 of his testimony that transient flow and pressure changes resulting from a design basis event would exacerbate leak growth and further reduce the ability of buried piping systems to perform their safety functions?

A32. (SPW, BRS) No. The coatings and lining of the buried SSW piping, and the coating and choice of materials of the buried CSS piping, should prevent any leaks in the first place. Furthermore, the tests that are routinely conducted to confirm the ability of these systems to perform their intended functions subject the system components to the same pressures and flow rates that would occur during a design basis event.

Q33. What is your response to Mr. Gundersen's claim in ¶ 12.4.11 that cathodic protection should be installed?

A33. (ABC, WHS) As long as the coatings maintain their integrity, cathodic protection is unnecessary. The aging management program found acceptable in section XI.M34 of the GALL Report does not rely on cathodic protection.

Q34. In paragraph 15 of his testimony, Mr. Gundersen attempts to draw an analogy between Byron Nuclear Power Station and PNPS. Please explain whether and how this experience at Byron applies to the PNPS CSS and SSW system buried pipes.

A34. (ABC, WHS, SPW) The event at Byron has no application to the buried CSS and SSW system piping at PNPS. Pilgrim Watch Exhibit 7, "Help Wanted: Dutch Boy at Byron," Union of Concerned Scientists (2007), indicates that the staff at Byron found a leak in the essential service water (ESW) system piping. However, the photographs in Exhibit 7 show that the circumstances surrounding this leak are entirely dissimilar to the buried PNPS piping in that (1) the piping at Byron was not buried and (2) the piping was not wrapped. Furthermore, there is also no discussion of any aging management program applied at Byron. Thus, the incident at Byron does not indicate any deficiency in the BPTIP.

VII. The Finding of Tritium Does Not Show a Failure of the PNPS AMPs

Q35. Do you agree with Mr. Gundersen (paragraph 16) that the recent discovery of tritium means that a significant safety system has been compromised?

A35. (BRS, SPW) No. The only buried piping subject to this contention that serves a safety related function is the buried piping in the SSW system. The SSW system does not normally contain any radioactivity. Moreover, the system has no history of cross contamination that would have introduced radioactivity into the SSW discharge piping, and regular monitoring of the discharge has never indicated the presence of radioactivity. Therefore, the recent measurements of tritium provide no indication that the SSW system has been compromised.

With respect to the CSS, while the CSTs are the preferred source of water for the HPCI and RCIC systems, the CSS is not the assured (safety-related) source of water for these systems. As already stated, the CSTs are not designed to withstand the design basis earthquake. Rather, the torus is the safety-related source of water for the HPCI and RCIC systems. Thus, the buried CSS piping does not have an intended safety function (i.e., the CSS is the preferred source, but not the relied upon source of water to mitigate an accident).

Moreover, the concentration of tritium in the CST is on the order of 10,000,000 pCi/l, and there is a monitoring well immediately adjacent to the buried CSS piping. If the CSS piping were leaking, one would expect substantial levels of tritium in this adjacent well. In contrast, the measurement of tritium in the well adjacent to the CSS piping is near background.

Q36. If the CSS piping does not have a safety function that is relied upon, why did Entergy include it within the scope of its license renewal application?

A36. (ABC, BRS) Entergy performed scoping at the system level. Entergy conservatively interpreted 10 C.F.R. § 54.4(a)(1) and included the CSS because portions of the CSS piping from the CSTs are directly connected to portions of the HPCI and RCIC systems, even though the CSTs are not relied upon to mitigate accidents. Entergy conservatively credited the CSTs under 10 C.F.R. § 54.4(a)(3), because the HPCI and RCIC systems are relied upon in the Appendix R shutdown analyses. However, the Appendix R shutdown analyses only credit the HPCI and RCIC functions and place no particular reliance on the CSTs as the source of water for these functions. Therefore, our decision to include the CSS within the scope of license renewal was a conservative decision.

Q37. Do you agree with Mr. Gundersen that the release of tritium indicates a leak in a system that was in the past radioactive?

A37. (BRS, SPW) No. There is no indication that the trace levels of tritium in monitoring wells are the result of system leakage. It could well be the result of deposition of gaseous releases from the plant. Furthermore, as discussed above, the tritium does not indicate any release from components subject to this contention.

Q38. Do you agree with Mr. Gundersen that the detection of tritium indicates a failure of Entergy's aging management programs?

A38. (ABC, BRS) No. As discussed above, the presence of very low levels of tritium in the monitoring wells does not signify any leakage from the buried SSW or CSS piping, nor do the tritium findings show a failure of the PNPS AMPs for the CSS and SSW system buried pipes, of which the BPTIP is yet to be implemented. Indeed, the capability of the CSS and the SSW system buried pipes to perform their intended function continues to be reaffirmed by the periodic surveillance tests and monitoring described in our original testimony.

Q39. Do you agree with Mr. Gundersen that the detection of tritium may indicate that the buried SSW and CSS piping may be unable to perform its function?

A39. (BRS, SPW) No. As stated above, (1) there is no indication that the CSS or SSW buried pipes are the source of the tritium, and (2) in addition to the aging management programs for these pipes, the regular monitoring and surveillance tests described in our original testimony provide reasonable assurance that both systems have been, and will continue to be able to perform their intended functions. Additionally, Entergy's Answer to Board Questions, dated February 11, 2008, ("February 11 Answer"), Entergy Exhibit 9, provides further evidence of reasonable assurance that these systems will be able to perform their intended functions.

VIII. Mr. Gundersen's Conclusions

Q40. Mr. Gundersen concludes in paragraph 18 of his testimony that PNPS should "establish critical baseline data." Do you agree?

A40. (ABC, BRS, SPW, WHS) No. As discussed above, we do not agree. Mr. Gundersen does not identify what critical baseline data should be established, much less indicate why such undefined data is critical. As we have discussed, we have sufficient information to asses the condition of the coatings to determine whether they remain effective in preventing corrosion from occurring. Therefore, we are not trending corrosion rates, or any other degradation rate.

Q41. Please address the second conclusion, at paragraph 18 of Mr. Gundersen's testimony, that PNPS should "[r]educe the future corrosion rate."

A41. (ABC, BRS, SPW, WHS) This conclusion ignores the use of corrosion resistant metals, CIPP liners, permanent coal-tar and epoxy coatings, and soil management techniques at PNPS that all lead to one thing: the prevention of corrosion in the first place. Mr. Gundersen would like PNPS to reduce the future corrosion rate. In fact, our programs at PNPS are intended to provide reasonable assurance that such corrosion does not occur in the first place.

Q42. Mr. Gundersen again states at paragraph 18 of his testimony that PNPS should "[i]mprove monitoring frequency and coverage." Do you agree?

A42. (ABC, BRS, SPW, WHS) No. Mr. Gundersen has shown no need or basis for increasing the frequency of inspections for the buried SSW and CSS piping. PNPS inspects – at a minimum – in-scope buried piping within ten years of license renewal and within ten years after license renewal. PNPS also takes full advantage of unscheduled opportunities to inspect in-scope buried piping. Industry as well as PNPS experience with coated buried piping shows that such inspections are sufficient to provide reasonable assurance of the continued integrity and capability of buried piping systems to perform their intended functions. Moreover, the continued capability of those systems to perform their intended functions is confirmed by the periodic surveillance tests and monitoring described in our original testimony.

Q43. Mr. Gundersen's finally concludes, at paragraph 18 of his testimony, that PNPS should "[i]ncrease the Monitoring Well Program to actively look for leaks once they have occurred" in order to mitigate the serious consequences of undetected leaks. Do you agree?

A43. (ABC, BRS, SPW, WHS) No. Not at all. The subject of the contention is "[W]hether Pilgrim's existing AMPs have elements that provide appropriate assurance as required under relevant NRC regulations that the buried pipes...will not develop leaks so great as to cause those pipes...to be unable to perform their intended safety functions." Pilgrim has shown that its existing AMPs, coupled with routine system testing and monitoring, assure that the in-scope buried pipes will not develop leaks so great that their ability to perform their intended safety functions could be compromised. Moreover, as discussed in our original testimony, the periodic surveillance tests and monitoring conducted at PNPS provide a much more direct and immediate method than monitoring wells to detect leakage that could impair the capability of the CSS and SSW system to perform their license renewal intended functions.

IX. Answer to Licensing Board's Questions of February 21, 2008

Q44. In the Licensing Board's Order and Notice of February 21, 2008, the Board asks "[h]ow large of a leak can the CSS withstand before its ability to satisfy its intended safety function is challenged, and how small of a leak is certain to be detected?" Order at 2. Please respond to the first part of this question concerning the size of a leak that the CSS can withstand "before its ability to satisfy its intended safety function is challenged."

A44. (ABC, BRS) As discussed in Entergy's February 11 Answer to Board Questions, no amount or rate of leakage from the CSS buried piping could challenge the ability of the HPCI and RCIC systems to perform their intended safety functions. While the CSTs are the preferred source of water for the HPCI and RCIC systems (because of water purity), the assured (i.e. safety-related) source of water is the torus. As stated, above the CSTs are not relied on following design basis events such as, for example, the design basis earthquake.

Thus, no amount of leakage would impair the intended safety function of the CSS buried piping, since it has no intended safety function.

In terms of serving as the preferred source of water for the HPCI and RCIC pumps, as discussed in our February 11 Answer, the CSS buried piping can withstand a leak on the order of 500 gallons per minute in the short term (i.e., between the 4-hour monitoring intervals of the CST water levels) and still remain capable of providing the preferred source of water to the HPCI and RCIC systems. This conservatively assumes that the two CSTs are not hydraulically connected, so that the leak would have the maximum drawdown on a single tank. If both tanks were hydraulically connected so that they float at a common level (which is the normal configuration), it would take twice as long for such a leak to reduce water in the CSTs to the levels reserved for HPCI and RCIC.

In the longer term, any leak rate exceeding the makeup capability of the plant would, if uncorrected, eventually challenge the ability of the CSTs to provide a preferred source of water to the HPCI and RCIC systems. As discussed in our February 11 Answer, the demineralized water transfer system ("DWTS") can provide up to 110 gallons per minute of makeup water for as long as there is water in the 50,000 gallon demineralized water storage tank. If the water in the tank were exhausted, the makeup capacity would then be limited by the production capacity of the plant demineralizers, which is about 25 gallons per minute. However, the possibility of such leakage going uncorrected is not credible. If there were leakage exceeding the makeup capability, the level in the CSTs would eventually drop below 30 feet, at which time corrective action would be required under PNPS procedures. This corrective action required when level drops below 30 feet would occur long before the level reaches the approximately 11 feet reserved for HPCI and RCIC. Moreover, we would expect that the plant operators would notice and correct any leakage even before CST levels were reduced below 30 feet, because the increase in the operation of the DWTS would be readily apparent.

Q45. What typically is the amount of water used in operating the CSS?

A45. (BRS) The average water used in 2007 per month that the plant was in operation was approximately 200,000 gallons. This equates to a normal use or loss of water of approximately 4.5 gpm. As such, a leakage rate of 500 gpm is more than two orders of magnitude greater than the normal consumption and would certainly be detected, and even a leakage rate of 25 gpm would be more than 5 times the normal consumption.

Q46. Please respond to the second part of the Board's first question, "how small of a leak [in the common CSS buried piping] is certain to be detected?"

A46. (ABC, BRS) The size of a leak that is certain to be detected varies depending on the time period. As stated, the normal usage of water from the CSS is about 4.5 gpm. The capacity of the DWTS is approximately 25 gpm. As such, a leak rate on the order of 25 gpm would be readily detectable.

A leak of 25 gallons per minute coupled with normal usage of water from the CSTs would exceed the makeup capacity of the DWTS water treatment equipment. This condition would result in a continually decreasing total inventory in the demineralized water storage tank and in the CSTs. Moreover, the makeup system would have to operate continuously, 24 hours a day, even though the water level in the demineralizer tank and the CSTs would be decreasing. This would be outside the norm and easily recognized.

With normal usage of water of approximately 4.5 gpm, the makeup system typically needs to operate 4 to 5 hours each day. In contrast, a 25 gallon leakage rate (over and above the approximate 4.5 normal gpm usage) would, over a two day period, cause a loss of approximately 14,000 gallons from the CSTs, or a foot drop in each of the CSTs, assuming both were in operation even though the makeup system would be operating continuously 24 hours a day during these two days. Such circumstances would be far outside the norm and would be certain to be recognized within this timeframe.

A 125 gallons per minute from the buried CSS piping would be readily detectable within four hours. A leak rate of 125 gpm, coupled with the normal usage of water from the CSS would lower the CST levels by about two feet in four hours. This would be far greater than the decrease that occurs from normal usage over a four hour period – on the order of 0.2 feet. Operators in the control room would be expected to notice such an order of magnitude decrease over a four-hour period.

Q47. In the Licensing Board's Order and Notice of February 21, 2008, the Board asked a second question as follows. "With regard to corrosion-induced small leaks that might grow rapidly into large enough leaks to challenge the ability of the CSS to satisfy its intended safety function, the parties shall provide, to the extent of their capability, concise and specific technical testimony addressing the reasonably expected growth in leakage rate over times ranging from at least four hours to three days." Order at 2. What is your response to this question from the Board?

A47. (ABC, BRS, WHS) Corrosion induced leakage in the buried CSS piping is not expected because (1) the piping is made of corrosion resistant stainless steel; (2) the piping is further protected by an exterior wrapping; (3) the exterior environmental (engineered fill above the water table) is not conducive to degradation; and (4) the interior environment (controlled water chemistry, no normal flow, no thermal stress, low temperature) is not conducive to degradation. Even if leakage were to occur, there is no credible mechanism that would cause any significant increase of the leakage rate.

Operating experience indicates that buried stainless steel piping wrapped with protective coating is not susceptible to corrosion mechanisms. In the absence of a reasonably credible aging mechanism to cause a leak, it is difficult to postulate an expected growth in leakage rate over time. Even if the protective coating were ignored, the corrosion aging mechanisms applicable to stainless steel piping – pitting corrosion, crevice corrosion, and microbiologically influenced corrosion – are slow acting (stress corrosion cracking is not credible because of the low operating temperatures). Furthermore, since the tank supplying the buried CSS piping is at atmospheric pressure, there is little driving head to cause leakage to rapidly increase.

Therefore, a credible mechanism cannot be postulated that would cause a four-fold increase in leak rate from the minimum detectable leakage for a four-hour period (of 125 gpm) over a subsequent four-hour period. A four-fold leak rate increase to 500gpm over a four hour period would not challenge the ability of the CSS to perform its license renewal intended function, as already discussed.

Likewise, it is unlikely that a leak rate of as little as 25 gpm would double over the course of three days. Again, there is no credible mechanism that would cause a significant growth in leak rate over the three day period. Increasing the leak rate to 50 gpm over a three day period would not challenge the ability of the CSS to perform its license renewal intended function.

In summary, the potential aging mechanisms that might initiate the leak – even assuming the degradation and loss of the protective coatings – are slow acting mechanisms that are not expected to cause a rapid increase of the leak rate. Furthermore, there are no driving forces that could lead to accelerated growth of any leak that might be postulated to occur.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board Panel

In the Matter of	)	
	)	
Entergy Nuclear Generation Company and	)	Docket No. 50-293-LR
Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

DECLARATION OF ALAN B. COX IN SUPPORT OF ENTERGY'S REBUTTAL TESTIMONY ON PILGRIM WATCH CONTENTION 1

I, Alan B. Cox, do hereby state the following:

I am the Technical Manager, License Renewal for Entergy Nuclear. My business address is 1448 State Road 333, Russellville, AR 72802. I was involved in preparing the license renewal application and developing aging management programs for the Pilgrim Nuclear Power Station license renewal project and have extensive experience and knowledge in the preparation of license renewal applications.

I provide this declaration in support of Entergy's rebuttal testimony on Pilgrim Watch Contention 1. I attest to the accuracy of those statements attributed to me (that material marked by my initials in Entergy's rebuttal testimony), support them as my own, and endorse their introduction into the record of this proceeding. I declare under penalty of perjury that those statements, and my statements in this declaration, are true and correct to the best of my knowledge, information, and belief.

Executed on 6 MAR 08 (Date)

[signature]
Alan B. Cox

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board Panel

In the Matter of	)	
	)	
Entergy Nuclear Generation Company and	)	Docket No. 50-293-LR
Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

DECLARATION OF WILLIAM H. SPATARO IN SUPPORT OF ENTERGY'S REBUTTAL TESTIMONY ON PILGRIM WATCH CONTENTION 1

I, William H. Spataro, do hereby state the following:

Until December 31, 2007, I was the Senior Staff Engineer-Corporate Metallurgist with Entergy Nuclear. My Personal Address is 2 Burning Brush Court, Pomona, NY 10970. In that position I provided technical support in metallurgy, corrosion, welding, and forensic investigation in support of Entergy's operation of its nuclear plants. I am a National Board Registered Certified Nuclear Safety Related Coating Engineer and have extensive experience in the coating and corrosion of buried pipes.

I provide this declaration in support of Entergy's rebuttal testimony on Pilgrim Watch Contention 1. I attest to the accuracy of those statements attributed to me (that material marked by my initials in Entergy's rebuttal testimony), support them as my own, and endorse their introduction into the record of this proceeding. I declare under penalty of perjury that those statements, and my statements in this declaration, are true and correct to the best of my knowledge, information, and belief.

Executed on 02/29/08 (Date)

William H Spataro
William H. Spataro

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board Panel

In the Matter of	)	
	)	
Entergy Nuclear Generation Company and	)	Docket No. 50-293-LR
Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

DECLARATION OF BRIAN R. SULLIVAN IN SUPPORT OF ENTERGY'S REBUTTAL TESTIMONY ON PILGRIM WATCH CONTENTION 1

I, Brian R. Sullivan, do hereby state the following:

I am the Engineering Director for Pilgrim Nuclear Power Station ("PNPS"). My business address is 600 Rocky Hill Road, Plymouth, MA 02360. I am currently responsible for engineering support at PNPS and I am knowledgeable of the intended functions for license renewal components and of the aging management programs credited for buried pipes and tanks for PNPS license renewal.

I provide this declaration in support of Entergy's rebuttal testimony on Pilgrim Watch Contention 1. I attest to the accuracy of those statements attributed to me (that material marked by my initials in Entergy's rebuttal testimony), support them as my own, and endorse their introduction into the record of this proceeding. I declare under penalty of perjury that those statements, and my statements in this declaration, are true and correct to the best of my knowledge, information, and belief.

Executed on 6 March 08 (Date)

[signature]
Brian R. Sullivan

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board Panel

In the Matter of	)	
	)	
Entergy Nuclear Generation Company and	)	Docket No. 50-293-LR
Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

DECLARATION OF STEVEN P. WOODS IN SUPPORT OF ENTERGY'S REBUTTAL TESTIMONY ON PILGRIM WATCH CONTENTION 1

I, Steven P. Woods, do hereby state the following:

I am the Manager, Engineering Programs and Components for Pilgrim Nuclear Power Station ("PNPS"). My business address is 600 Rocky Hill Road, Plymouth, MA 02360. I am knowledgeable of the PNPS aging management program for buried pipes and tanks and was responsible for site engineering to install buried salt service water inlet piping at PNPS in 1993.

I provide this declaration in support of Entergy's rebuttal testimony on Pilgrim Watch Contention 1. I attest to the accuracy of those statements attributed to me (that material marked by my initials in Entergy's rebuttal testimony), support them as my own, and endorse their introduction into the record of this proceeding. I declare under penalty of perjury that those statements, and my statements in this declaration, are true and correct to the best of my knowledge, information, and belief.

Executed on 2/29/2008 (Date)

Steven P. Woods
Steven P. Woods

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
Entergy Nuclear Generation Company	)	Docket No. 50-293-LR
and Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

Entergy Exhibits to Rebuttal Testimony of Alan Cox, Brian Sullivan, Steve Woods, and William Spataro on Pilgrim Watch Contention 1, Regarding Adequacy of Aging Management Program for Buried Pipes and Tanks and Potential Need for Monitoring Wells to Supplement Program and Response to Atomic Safety and Licensing Board's Questions of February 21, 2008

Exhibit	Document
6	License Renewal Application, Appendix A, Section A.2.1.2 (Excerpts)
7	NUREG-1891, "Safety Evaluation Report Related to the License Renewal of Pilgrim Nuclear Power Station," Appendix A (Sept. 2007, Published Nov. 2007) (Excerpts)
8	License Renewal Application, Appendix B.0.3
9	Entergy's Answer to Board Questions, dated February 11, 2008

NUREG-1891

Safety Evaluation Report
Related to the License Renewal of Pilgrim Nuclear Power Station

Docket No. 50-293

Entergy Nuclear Operations, Inc.

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, DC 20555-0001

APPENDIX A

PNPS LICENSE RENEWAL COMMITMENTS

During the review of the Pilgrim Nuclear Power Station (PNPS) license renewal application (LRA) by the staff of the US Nuclear Regulatory Commission (NRC) (the staff), Entergy Nuclear Operations, Inc. (the applicant), made commitments related to aging management programs (AMPs) to manage the aging effects of structures and components prior to the period of extended operation. The following table lists these commitments along with the implementation schedules and the sources for each commitment.

APPENDIX A: PNPS LICENSE RENEWAL COMMITMENTS				
Number	**Commitment**	**LRA Section(s)**	**Enhancement or Implementation Schedule**	**Source**
1	Implement the Buried Piping and Tanks Inspection Program as described in LRA Section B.1.2.	B.1.2	June 8, 2012	Letters 2.06.003 and 2.06.057
2	Enhance the implementing procedure for ASME Section XI inservice inspection and testing to specify that the guidelines in Generic Letter 88-01 or approved BWRVIP-75 shall be considered in determining sample expansion if indications are found in Generic Letter 88-01 welds.	B.1.6	June 8, 2012	Letters 2.06.003 and 2.06.057
3	Inspect fifteen (15) percent of the top guide locations using enhanced visual inspection technique, EVT-1, within the first 18 years of the period of extended operation, with at least one-third of the inspections to be completed within the first six (6) years and at least two-thirds within the first 12 years of the period of extended operations. Locations selected for examination will be areas that have exceeded the neutron fluence threshold.	B.1.8	Inspections completed within the first 18 years of the period of extended operation (at least one-third of these inspections completed within the first six years and at least two-thirds completed within the first 12 years)	Letters 2.06.003, 2.06.057, 2.06.064, and 2.06.081

APPENDIX A
UPDATED FINAL SAFETY ANALYSIS REPORT SUPPLEMENT

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A.0 INTRODUCTION

This appendix provides the information to be submitted in an Updated Final Safety Analysis Report Supplement as required by 10 CFR 54.21(d) for the Pilgrim Nuclear Power Station (PNPS) License Renewal Application (LRA). The LRA contains the technical information required by 10 CFR 54.21(a) and (c). Appendix B of the PNPS LRA provides descriptions of the programs and activities that manage the effects of aging for the period of extended operation. Section 4 of the LRA documents the evaluations of time-limited aging analyses for the period of extended operation. Appendix B and Section 4 have been used to prepare the program and activity descriptions for the PNPS Updated Final Safety Analysis Report (UFSAR) Supplement information in this appendix.

This appendix is divided into two parts. The first part identifies changes to the existing sections of the UFSAR related to license renewal. The second part provides new information to be incorporated into the UFSAR. The information presented in both parts will be incorporated into the UFSAR following issuance of the renewed operating license. Upon inclusion of the UFSAR Supplement in the PNPS UFSAR, future changes to the descriptions of the programs and activities will be made in accordance with 10 CFR 50.59.

A.2 NEW UFSAR SECTION

The following information will be integrated into the UFSAR to document aging management programs and activities credited in the PNPS license renewal review and time-limited aging analyses evaluated for the period of extended operation. References to other sections are to UFSAR sections, not to sections in the LRA.

A.2.0 Supplement for Renewed Operating License

The Pilgrim Nuclear Power Station license renewal application (Reference A.2-1) and information in subsequent related correspondence provided sufficient basis for the NRC to make the findings required by 10 CFR 54.29 (Final Safety Evaluation Report) (Reference A.2-2). As required by 10 CFR 54.21(d), this UFSAR supplement contains a summary description of the programs and activities for managing the effects of aging (Section A.2.1) and a description of the evaluation of time-limited aging analyses for the period of extended operation (Section A.2.2). The period of extended operation is the 20 years after the expiration date of the original operating license.

A.2.1 Aging Management Programs and Activities

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

PNPS 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 Entergy Quality Assurance Program applies to safety-related structures and components. Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished per the existing PNPS corrective action program and document control program and are applicable to all aging management programs and activities that will be required during the period of extended operation. The confirmation process is part of the corrective action program and includes reviews to assure that proposed actions are adequate, 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.

A.2.1.1 Boraflex Monitoring Program

The Boraflex Monitoring Program assures that degradation of the Boraflex panels in the spent fuel racks does not compromise the criticality analysis in support of the design of the spent fuel storage racks. The program relies on (1) neutron attenuation testing, (2) determination of boron loss through correlation of silica levels in spent fuel pool water samples and periodic areal density measurements, and (3) analysis of criticality to assure that the required 5% subcriticality margin is maintained.

A.2.1.2 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, stainless steel, and titanium components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement.

A focused inspection will be performed within the first 10 years of the period of extended operation, unless an opportunistic inspection (or an inspection via a method that allows assessment of pipe condition without excavation) occurs within this ten-year period.

A.2.1.3 BWR CRD Return Line Nozzle Program

Under the BWR CRD Return Line Nozzle Program, PNPS has cut and capped the CRD return line nozzle to mitigate cracking and continues inservice inspection (ISI) examinations to monitor the effects of crack initiation and growth on the intended function of the control rod drive return line nozzle and cap. ISI examinations include ultrasonic inspection of the nozzle-to-vessel weld and ultrasonic inspection of the dissimilar metal weld overlay at the nozzle.

A.2.1.4 BWR Feedwater Nozzle Program

Under the BWR Feedwater Nozzle Program, PNPS has removed feedwater blend radii flaws, removed feedwater nozzle cladding, and installed a triple-sleeve-double-piston sparger to mitigate cracking. This program continues enhanced inservice inspection (ISI) of the feedwater nozzles in accordance with the requirements of ASME Section XI, Subsection IWB and the recommendation of General Electric (GE) NE-523-A71-0594 to monitor the effects of cracking on the intended function of the feedwater nozzles.

A.2.1.5 BWR Penetrations Program

The BWR Penetrations Program includes (a) inspection and flaw evaluation in conformance with the guidelines of staff-approved boiling water reactor vessel and internals project (BWRVIP) documents BWRVIP-27 and BWRVIP-49 and (b) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-130 to ensure the long-term integrity of vessel penetrations and nozzles.

B.0.3 PNPS CORRECTIVE ACTIONS, CONFIRMATION PROCESS AND ADMINISTRATIVE CONTROLS

Three attributes common to all aging management programs are corrective actions, confirmation process and administrative controls. Discussion of these attributes is presented below. Corrective actions have program-specific details which are included in the descriptions of the individual programs in this report, but further discussion of the confirmation process and administrative controls is not necessary and is not included in the descriptions of the individual programs.

Corrective Actions

PNPS quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. Conditions adverse to quality, such as failures, malfunctions, deviations, defective material and equipment, and nonconformances, are promptly identified and corrected. In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the nonconformance is determined and that corrective action is taken to preclude recurrence. In addition, the root cause of the significant condition adverse to quality and the corrective action implemented are documented and reported to appropriate levels of management.

Confirmation Process

PNPS quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The Entergy Quality Assurance Program applies to PNPS safety-related structures and components. Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished per the existing PNPS corrective action program and document control program. The confirmation process is part of the corrective action program and includes

- reviews to assure that proposed actions are adequate,
- 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. The corrective action program constitutes the confirmation process for aging management programs and activities. The PNPS confirmation process is consistent with NUREG-1801.

Administrative Controls

PNPS quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The Entergy Quality Assurance Program applies to PNPS safety-related structures and components. Administrative (document) control for both safety-related and nonsafety-related structures and components is accomplished per the existing document control program. The PNPS administrative controls are consistent with NUREG-1801.

B.0.4 OPERATING EXPERIENCE

Operating experience for the programs and activities credited with managing the effects of aging was reviewed. The operating experience review included a review of corrective actions resulting in program enhancements. For inspection programs, reports of recent inspections, examinations, or tests were reviewed to determine if aging effects have been identified on applicable components. For monitoring programs, reports of sample results were reviewed to determine if parameters are being maintained as required by the program. Also, program owners contributed evidence of program success or weakness and identified applicable self-assessments, QA audits, peer evaluations, and NRC reviews.

B.0.5 AGING MANAGEMENT PROGRAMS

The following aging management programs are described in the sections listed of this appendix. Programs are identified as either existing or new. The programs are either comparable to programs described in NUREG-1801 or are plant-specific. The correlation between NUREG-1801 programs and PNPS programs is shown in Table B-2, with plant-specific programs listed near the end.

Table B-1
Aging Management Programs

1)	Boraflex Monitoring Program	B.1.1	existing
2)	Buried Piping and Tanks Inspection Program	B.1.2	new
3)	BWR CRD Return Line Nozzle Program	B.1.3	existing
4)	BWR Feedwater Nozzle Program	B.1.4	existing
5)	BWR Penetrations Program	B.1.5	existing
6)	BWR Stress Corrosion Cracking Program	B.1.6	existing
7)	BWR Vessel ID Attachment Welds Program	B.1.7	existing

February 11, 2008

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board Panel

In the Matter of	)	
	)	
Entergy Nuclear Generation Company and	)	Docket No. 50-293-LR
Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

ENTERGY'S ANSWER TO BOARD QUESTIONS

Entergy Nuclear Generation Company and Entergy Nuclear Operations, Inc. ("Entergy") provide the following responses to the questions posed by the Atomic Safety and Licensing Board in its January 31, 2008 Order. A Declaration of Stephen J. Bethay is provided in support of these responses.

1. With regard to the Condensate Storage System ("CSS") -
a. What is the minimum leakage rate that is certain to be detectable by the testing of the condensate storage tank ("CST") water level every four hours and, conversely, what is the maximum leakage rate that would not be detected by that testing? Provide a detailed statement of the basis of and sources for your answer.

Response: The purpose of the 4-hour testing of CST water level is to determine that the water level remains above the required water levels, including the 10'-5" reserved for HPCI and RCIC, and not specifically to determine a leak rate. Under normal operation, the level of the CSTs is dynamic (i.e. the CST levels fluctuate as they provide makeup or receive condensate discharge to maintain appropriate condenser water level). Therefore, under normal operation, there is no specific leakage rate that would be detected by or could be readily correlated with the four-hour test results.

Under the Pilgrim procedures, normal CST level is maintained between 30 to 38 feet, and corrective action is required if water level drops below 30 feet. Further, 10'-5" of water is maintained solely to support HPCI and RCIC. Therefore, the level would have to drop at least ~19.5 feet before there would be insufficient water to maintain this reserve. Since the water level in each tank is monitored to the nearest foot every four hours, an ~19.5 foot drop would be clearly detectable. Since each foot of water in a CST represents approximately 7,000 gallons, a drop of 19.5 feet would correspond to a loss of 136,500 gallons.

More specifically, each CST is equipped with a level indicator which under Pilgrim procedures is monitored every 4 hours. Further, each CST is equipped with level switches, which trigger an alarm in the control room if water level decreases below 12.5 feet, and trip the condensate transfer pumps (i.e. terminate use for normal operations) if CST level reaches 11.5 feet. If the water level continues to decrease, the HPCI and RCIC suction path is switched (when CST level reaches 8 and 3.5 feet, respectively) to the torus, which is the assured (safety-related) source of water for the HPCI and RCIC functions. These setpoints for swap-over to the torus ensure that net positive suction head to the HPCI and RCIC pumps is maintained.

As stated above, the level indicator measurements cannot be readily correlated with a leak rate during normal operations because the water level is dynamic. However, if a CST were under static conditions (i.e. no makeup or discharge), a level reduction of one foot (corresponding to the minimum change that would normally be recorded) between four hour tests would correspond to a leak rate of 30 gallons per minute.

b. What is the minimum leakage rate that is certain to be detected by the quarterly testing of the water flow from the reactor core isolation cooling ("RCIC") pump and the high pressure cooling injection ("HPCI") pump, and, conversely, what is the maximum leakage rate that *would not be detected by that testing? Provide a detailed statement of the basis of and sources for your answer.*

Response: The quarterly HPCI and RCIC system surveillance tests are not designed or intended to quantify a potential leakage rate from buried piping. Rather, these quarterly tests demonstrate system operability by verifying pump flow rate and discharge pressure. The test is performed by creating a flow path (through the buried pipe) with suction from and discharge to the CST. While these tests do not allow quantification of leakage rate, they do demonstrate that, even if leakage were occurring, the required flow from the CST to HPCI and RCIC would still be achieved.

c. What is the smallest leakage rate that could reasonably be expected to challenge the ability of the CSS system piping at issue to fail to satisfy its intended function(s) as relevant for license renewal? Provide a detailed statement of the basis of and sources for your answer.

Response: At the outset, no amount or rate of leakage from the CSS buried piping could challenge the ability of the HPCI and RCIC systems to perform their intended functions. While the CSTs are the preferred source of water for HPCI and RCIC (because of water purity), the assured (i.e. safety-related) source of water is the torus. If the CSS were unable to deliver water to the HPCI and RCIC pumps, for any reason, the HPCI and RCIC suction path would be switched to the torus.

While leakage from the CSS piping would not prevent the HPCI and RCIC functions from being performed, it could affect the ability of the CSTs to serve as the preferred source of water for HPCI and RCIC. Make-up to the CSTs is supplied from the demineralized water storage tank (DWST). The demineralized water transfer system (DWTS), which transfers water from the DWST to either CST, is supplied by two pumps each of which is rated at 110 gallons per minute. Since only one of the two pumps is normally in service, a maximum of 110 gallons per minute of makeup could be provided to either CST to compensate for a leak. If leakage from buried CSS piping were to exceed this rate, the volume of water in the CST could not be maintained, which would eventually[1] impact its ability to provide the preferred source of water to the HPCI and RCIC systems.

The smallest leakage rate that would challenge the ability of a CST to serve as the preferred source for HPCI and RCIC within a 4 hour interval is on the order of 500 gallons per minute. With regard to a leakage rate that would be detected by the 4 hour monitoring, one could hypothesize the following: Assume initial tank level is at the procedural minimum of 30 feet. A leak develops such that the level drops to the alarm setpoint (12.5 feet) just before the next 4 hour observation. In this case, a level reduction of 17.5 feet over a 4 hour period would represent a leakage rate of over 500 gpm. Because this leakage rate exceeds the make-up capability of the DWTS, the capability of the CST to act as the preferred source would not be recovered without corrective action. However, such a large leakage rate would likely cause visible effects, such as water leaking into the building, erosion of exterior ground surfaces, or significant amounts of visible water in exterior areas, that would be noticeable well within the 4-hour observation period.

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[1] For example, if the leakage rate from a CST were 220 gallons per minute (twice the makeup rate of a DWTS pump), it would take about 20 hours before the CST level would be reduced below the level reserved for HPCI and RCIC. The volume of water that would have to be lost to reduce the water level in the CST from its normal minimum (30 feet) to the level reserved for HPCI and RCIC (10.5 feet) is 136,500 gallons ([30 feet – 10.5 feet] x 7,000 gallons/foot). Assuming a single DWST pump provides makeup at its rated capacity, a leak of 220 gallons per minute would correspond to a net loss rate of 110 gallons per minute (220 gallons per minute leakage rate minus 110 gallons per minute makeup rate). The time it would take for this net loss rate to reduce the volume by 136,500 gallons is: 136,500 gallons ÷ [110 gallons per minute x 60 minutes/hour] ~ 20 hours.

Leakage from the buried piping would not be expected to affect the flow of water through the buried CSS line. The positive pressure in the piping would cause any leakage to flow out of the line, not in, so leakage would not be expected to introduce debris or cause blockage of the piping. Further, the key consideration in system operation is maintaining adequate suction pressure (i.e. net positive suction head) to the pumps. The CST and piping system design, in conjunction with the setpoints for swapping the HPCI and RCIC suction source to the torus, ensure adequate net positive suction head to the pumps. Thus, while some amount of water would be diverted from the piping to the ground which would serve to increase the rate of level decrease in the CST, this would merely accelerate the time at which the suction swap to the torus would be required. HPCI and RCIC functions would be unaffected.

2. With Regard to the Salt Service Water ("SSW") system – Explain how any leak in the SSW buried pipes that might carry radioactive water from the plant to the canal that dumps into the bay could challenge the ability of the SSW system to satisfy its intended function(s)? For example, is there any correlation between any potential leak in those pipes and any potential plugs in them that might prevent them from discharging water from the SSW, thereby impeding the ability to remove heat from the RBCCW? Provide a detailed statement of the basis of and sources for your answer.

Response: The SSW system discharge piping is an open-ended run of unobstructed piping. Leakage is generally not a concern for an open-ended discharge pipe.

The external surface of the carbon steel discharge pipe is protected by either a coal tar wrapping or epoxy coating. The interior of the discharge piping is protected by a ½" thick cured-in-place-pipe (CIPP) lining, consisting of polyester felt material with a resin and catalyst system or an epoxy resin and hardener system, which forms a smooth, hard inner protective surface. These coatings and linings are designed to prevent internal and external corrosion. For leakage to occur, there would have to be a failure of the external coating, a through wall failure of the metal pipe, and a failure of the CIPP liner. The likelihood of these three barriers being breached is remote.

Further, in the unlikely event of leakage from the discharge piping, such leakage would not be expected to have any effect on the SSW system's ability to perform its intended function. Leakage would simply result in some salt water being discharged to the ground rather than to the bay. Further, because there is a positive pressure differential within the discharge piping, in-leakage of dirt or debris that might block the discharge line would not be expected. Indeed, even if dirt were introduced, it would likely be swept away with the discharge flow. Moreover, if dirt or debris were somehow accumulating, any significant diminishment of flow would be detected by the daily monitoring of the heat exchange capability of the SSW system. Thus, only if degradation of the SSW discharge piping were somehow to progress to the point of pipe collapse would the SSW system's ability to satisfy its intended function be challenged. The design and construction of the SSW discharge piping, including external coatings and internal liner, make such a failure mechanism not credible.

Respectfully Submitted,

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Dated: February 11, 2008

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board Panel

In the Matter of	)	
	)	
Entergy Nuclear Generation Company and	)	Docket No. 50-293-LR
Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

DECLARATION OF STEPHEN J. BETHAY IN SUPPORT OF ENTERGY'S ANSWER TO BOARD QUESTIONS

I, Stephen J. Bethay, do hereby state the following:

I am the Director, Nuclear Safety Assurance, for Pilgrim Nuclear Power Station ("PNPS"). My business address is 600 Rocky Hill Road, Plymouth, MA 02360. A statement of my professional qualifications is attached.

I provide this declaration in support of Entergy's answers to the questions asked by the Atomic Safety and Licensing Board in its January 31, 2008 Order. I have knowledge of the matters stated therein, and declare under penalty of perjury that Entergy's answers are true and correct to the best of my knowledge, information, and belief.

Stephen J. Bethay

Stephen J. Bethay

Executed: February 11, 2008

Stephen J. Bethay

Director, Nuclear Safety Assurance

Pilgrim Nuclear Power Station

Responsibility:

Responsible for management and oversight of support functions of the Pilgrim Station including Licensing, Corrective Action Program, Quality Assurance, Emergency Preparedness, and Security,.

Experience:

2004- Present Director, Nuclear Safety Assurance, Pilgrim Station

2001- 2004 Engineering Director, Entergy Nuclear, Pilgrim Station

Responsible for all aspects of engineering support of Pilgrim Station.

1999-2001 Station Services Superintendent, Entergy Nuclear, Pilgrim Station

Responsible for non-power block facility maintenance, radioactive waste shipping, and facility decontamination.

1997-1999 Licensing Director, Entergy Operations Inc., corporate

Responsible for corporate licensing support of the Riverbend, Grand Gulf, Waterford 3 and Arkansas Nuclear One facilities.

1994-1997 Manager, Engineering, Southern Nuclear Operating Company

Responsible for corporate engineering support including design and project management for the E. I. Hatch Nuclear Plant

1988-1994 Licensing Manager, Southern Nuclear Operating Company

Responsible for licensing and regulatory support for the E. I. Hatch Nuclear Plant.

1981-1988 Various engineering and licensing positions associated with the E.I. Hatch Nuclear Plant

1977-1981 Co-operative Education Student, Georgia Power Co., Bowen Steam Electric Plant

Education/Training:

(1981) B.S.-Mechanical Engineering, Auburn University

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(2001) SRO Certification, Pilgrim Nuclear Power Station

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	)	
(Pilgrim Nuclear Power Station)	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of "Entergy's Answer to Board Questions," dated February 11, 2008, were served on the persons listed below by deposit in the U.S. Mail, first class, postage prepaid, and where indicated by an asterisk by electronic mail, this 11th day of February, 2008.

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UNITED STATES OF AMERICA
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Entergy Nuclear Generation Company and	)	Docket No. 50-293-LR
Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-848-02-LR
	)	
(Pilgrim Nuclear Power Station)	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of "Rebuttal Testimony of Alan Cox, Brian Sullivan, Steve Woods, and William Spataro on Pilgrim Watch Contention 1, Regarding Adequacy of Aging Management Program for Buried Pipes and Tanks and Potential Need for Monitoring Wells to Supplement Program and Response to Atomic Safety and Licensing Board's Questions of February 21, 2008;" Declarations of Steven P. Woods, Alan B. Cox, Brian R. Sullivan and William H. Spataro "In Support Of Entergy's Rebuttal Testimony On Pilgrim Watch Contention 1;" and "Entergy Exhibits to Rebuttal Testimony of Alan Cox, Brian Sullivan, Steve Woods, and William Spataro on Pilgrim Watch Contention 1, Regarding Adequacy of Aging Management Program for Buried Pipes and Tanks and Potential Need for Monitoring Wells to Supplement Program and Response to Atomic Safety and Licensing Board's Questions of February 21, 2008," were served on the persons listed below by deposit in the U.S. Mail, first class, postage prepaid, and where indicated by an asterisk by electronic mail, this 6th day of March, 2008.

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