January 29, 2008

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

NRC STAFF INITIAL STATEMENT OF POSITION ON CONTENTION 1

INTRODUCTION

Pursuant to 10 C.F.R. §§ 2.1207(a)(1) and 2.337(g)(2) and the Atomic Safety and Licensing Board Panel's ("Board") December 19, 2007 Order,[1] the Staff of the U.S. Nuclear Regulatory Commission ("Staff") submits its initial written statement of position and written testimony with supporting affidavits on Pilgrim Watch's admitted contention. Appended to this filing is the Staff testimony and certifications of Dr. James A. Davis, Terence L. Chan, and Andrea T. Keim concerning Contention 1 and Staff's Exhibits 1 through 20. For the reasons set forth below and in the testimony filed herewith, the Staff submits that a careful evaluation of Pilgrim Watch's Contention 1 demonstrates that Pilgrim Watch's challenge to the Entergy Nuclear Generation Co. and Entergy Nuclear Operations, Inc. (collectively, "Entergy") application for renewal of the Pilgrim operating license cannot be sustained.

[1] Order (Revising Schedule for Evidentiary Hearing and Responding to Pilgrim Watch's December 14 and 15 Motions), (Dec. 19, 2007) (unpublished) ("Scheduling Order").

BACKGROUND

This matter arises from an application, filed by Entergy on January 25, 2006, to renew the operating license for the Pilgrim Nuclear Power Station ("Pilgrim") for an additional twenty-year period following the June 8, 2012 expiration date.[2] On May 25, 2006, Pilgrim Watch filed a petition to intervene in this matter.[3] Pilgrim Watch submitted five contentions for consideration by the Board. On October 16, 2006, the Board admitted two of those contentions.[4] As admitted, Pilgrim Watch Contention 1 reads:

> The Aging Management program proposed in the Pilgrim Application for license renewal is inadequate with regard to aging management of buried pipes and tanks that contain radioactively contaminated water, because it does not provide for monitoring wells that would detect leakage.[5]

On June 8, 2007, Entergy filed a summary disposition motion asserting that, as to the issues raised in Contention 1, there were no material facts in issue and, thus, Entergy was entitled to a decision as a matter of law.[6] The Staff filed a response supporting the motion and Pilgrim Watch opposed the motion.[7] On October 17, 2007, the Board issued a Memorandum and Order denying Entergy's motion.[8] It found a genuine dispute regarding:

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[2] *See* Letter from Michael Balduzzi, Entergy Nuclear Operations, to U.S. NRC, Re: License Renewal Application, (January 25, 2006) (Agencywide Documents and Access Management System (ADAMS) Accession No. ML060300028).

[3] Request for Hearing and Petition to Intervene by Pilgrim Watch (May 25, 2006).

[4] *Entergy Nuclear Generation Co. and Entergy Nuclear Operations Inc.* (Pilgrim Nuclear Power Station), LBP-06-23, 64 NRC 257 (2006) ("Memorandum and Order on Contentions"). The second admitted contention, Contention 3, was disposed of by summary disposition granted on October 30, 2007. *See Entergy Nuclear Generation Co. and Entergy Nuclear Operations, Inc.* (Pilgrim Nuclear Power Station), LBP-07-13, 66 NRC __ (Oct. 30, 2007) (slip op.).

[5] Memorandum and Order on Contentions at 315.

[6] Entergy's Motion for Summary Disposition of Pilgrim Watch Contention 1 (June 8, 2007).

[7] NRC Staff Response to Entergy's Motion for Summary Disposition of Pilgrim Watch Contention (continued. . .)

> whether those Pilgrim aging management programs, or AMPs, that relate to relevant buried pipes and tanks are adequate on their own, without need of any leak detection devices (Intervenors propose monitoring wells), to assure that the pipes and tanks in question will perform their intended functions and thereby protect public health and safety.[9]

To clarify for all parties involved, the Board refined the issue by stating that:

> the only issue remaining . . . is whether or not monitoring wells are necessary to assure that the buried pipes and tanks at issue will continue to perform their safety function during the license renewal period — or, put another way, whether Pilgrim's existing AMPs have elements that provide appropriate assurance as required under relevant NRC regulations that the buried pipes and tanks will not develop leaks so great as to cause those pipes and tanks to be unable to perform their intended safety functions.[10]

On October 29, 2007, Entergy filed a motion for reconsideration of the Board's denial of summary disposition of Contention 1.[11] The Board denied Entergy's Reconsideration Motion, finding that a genuine dispute continued to exist with respect to "whether Entergy's aging management program has leak detection provisions sufficient to prevent the subject buried pipes and tanks from failing to satisfy their intended safety function."[12]

(. . .continued)

1 (June 28, 2007); Pilgrim Watch's Answer Opposing Entergy's Motion for Summary Disposition of Pilgrim Watch Contention 1 (June 27, 2007).

[8] *Entergy Nuclear Generation Co. and Entergy Nuclear Operations, Inc.* (Pilgrim Nuclear Power Station), LBP-07-12, 66 NRC ___ (Oct. 17, 2007) (slip op.) ("Summary Disposition Order").

[9] *Id.* at 16.

[10] *Id.* at 18.

[11] Entergy's Motion for Reconsideration of LBP-07-12 (Oct. 29, 2007) ("Reconsideration Motion").

[12] Memorandum and Order (Ruling on Entergy's Motion for Reconsideration of [LBP]-07-12) (Nov. 14, 2007) (unpublished) at 4.

On December 19, 2007, the Board issued an order revising the schedule for the evidentiary hearing.[13] Within that Scheduling Order, the Board again attempted to clarify the scope of the proceeding, stating:

> Ongoing monitoring is not within the scope of this proceeding; only challenges to errors or omissions from the Applicant's Aging Management Program (AMP) are properly within the scope. The single admitted contention relates to whether or not Applicant's AMPs are sufficient to enable it to determine whether or not certain buried pipes and tanks are leaking at such great rates that they cannot satisfy their respective intended safety functions. Therefore, unless and until the Applicant expressly advises this Board and the Agency that it intends to rely upon monitoring wells for making its determination that buried pipes and tanks are not leaking at such great rates that they cannot satisfy their intended safety functions, information related to monitoring wells is irrelevant to the issues at hand before this Board.

Further, the Board detailed exactly what information each party is to submit in their prefiled direct testimony. Entergy was to:

> pipe-by-pipe and tank-by-tank: (a) clearly identify each buried pipe and tank which may potentially contain radioactive fluids; (b) identify the intended safety function of such pipe or tank; (c) specify the procedures by which Entergy will determine, during the license extension period, whether there are leaks present which might endanger the ability of that pipe or tank to meet its intended safety function, whether or not such procedures are part of routine maintenance and operation or part of the aging management program.[14]

The Staff and Pilgrim Watch were to respond with the same requested information and provide any other specifically relevant information.[15]

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[13] Scheduling Order at 1-2.

[14] *Id.* at 2-3.

[15] *Id.* at 3.

In response to the Scheduling Order, on December 21, 2007, Pilgrim Watch filed a motion for clarification seeking guidance on two issues: "(1) What buried pipes and tanks are now under consideration" and "(2) What materials must be provided by Entergy by January 8, 2008."[16] The Board denied the Clarification Motion.[17] In another response to the Scheduling Order, on December 28, 2007, Pilgrim Watch filed a motion for reconsideration of the Scheduling Order based chiefly upon the dissenting opinion provided by Judge Ann Marshall Young.[18] The Board denied this motion as well, and again made clear that the only issue remaining before the Board is that:

> either the application omits to describe the programs and procedures by which it will determine whether or not buried pipes and tanks containing radioactive fluids are leaking at such great rates that they cannot satisfy their respective designated safety functions, or that there are no such programs.[19]

For the reasons set forth below, the contention lacks merit.

DISCUSSION

I. Legal and Regulatory Requirements

The scope of license renewal proceedings is limited. The Commission's "[l]icense renewal reviews are not intended to 'duplicate the Commission's ongoing review of operating reactors.'" *Florida Power & Light Co.* (Turkey Point Nuclear Generating Plant, Units 3 & 4), CLI-01-17, 54 NRC 3, 7 (2001) (*citing* Final Rule, "Nuclear Power Plant License Renewal," 56 Fed. Reg. 64,943, 64,946 (Dec. 13, 1991)). Therefore, the license renewal safety review process focuses on the "potential detrimental effects of aging that are not routinely addressed by

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[16] Pilgrim Watch Motion for Clarification (Dec. 21, 2007) at 2 ("Clarification Motion").

[17] Order (Denying Pilgrim Watch's Motion for Clarification) (Jan. 11, 2008) (unpublished).

[18] Order (Denying Pilgrim Watch's Motion for Reconsideration) (Jan. 11, 2008) (unpublished).

[19] *Id.* at 8.

ongoing regulatory oversight programs." *Id*. Consequently, "10 C.F.R. Part 54 requires renewal applicants to demonstrate how their programs will be effective in managing the effects of aging during the period of extended operation." *Id.* at 8 (*citing* 10 C.F.R. § 54.21(a)). Applicants are required to "identify any additional actions, i.e., maintenance, replacement of parts, etc., that will need to be taken to manage adequately the detrimental effects of aging." *Id.* (*citing* Final Rule, "Nuclear Power Plant License Renewal; Revisions," 60 Fed. Reg. 22,461, 22,463 (May 8, 1995)). The Commission has recognized that these "[a]dverse aging effects generally are gradual and thus can be detected by programs that ensure sufficient inspections and testing." *Id.* (*citing* 60 Fed. Reg. at 22,475). License renewal proceedings are limited to a "review of the plant structures and components that will require an aging management review for the period of extended operation and the plant's systems, structures, and components that are subject to an evaluation of time-limited aging analyses." *Duke Energy Corp.* (McGuire Nuclear Station, Units 1 and 2; Catawba Nuclear Station, Units 1 and 2), CLI-01-20, 54 NRC 211, 212 (2001) (*citing* 10 C.F.R. §§ 54.21(a) and (c), 54.4; 60 Fed. Reg. 22,461).

Pilgrim Watch's Contention 1, as clarified, asks

> whether or not monitoring wells are necessary to assure that the buried pipes and tanks at issue will continue to perform their safety function during the license renewal period — or, put another way, whether Pilgrim's existing AMPs have elements that provide appropriate assurance as required under relevant NRC regulations that the buried pipes and tanks will not develop leaks so great as to cause those pipes and tanks to be unable to perform their intended safety functions.[20]

The adequacy of the Staff's review of Entergy's application is not at issue; instead, "the sole focus of the hearing is on whether the application satisfies NRC regulatory requirements." Final

[20] Summary Disposition Order at 18.

Rule, "Rules of Practice for Domestic Licensing Proceedings-Procedural Changes in the Hearing Process," 54 Fed Reg. 33,168, 33,171 (Aug. 11, 1989) (*citing Pacific Gas and Electric Co.* (Diablo Canyon Nuclear Power Plant, Units 1 and 2)*,* ALAB-728, 17 NRC 777, 807, *review declined,* CLI-83-82, 18 NRC 1309, 1983)). The overall burden is on Entergy to demonstrate that its AMPs for the buried pipes and tanks systems within the scope of license renewal are adequate to manage the aging effects so that their intended safety function will be maintained during the period of extended operations. *See* 10 C.F.R. § 2.325. Pilgrim Watch, however, must come forward with evidence supporting its claim that Entergy's AMPs are inadequate. *Louisiana Power & Light Co.* (Waterford Steam Electric Station, Unit 3), ALAB-732, 17 NRC 1076, 1093 (1983).

Although a plant's current licensing basis ("CLB")[21] will be reviewed during the course of license renewal, the Commission has determined that intervenors may not challenge the CLB because "such issues: (1) are not germane to aging management concerns; (2) previously have been the subject of thorough review and analysis; and, accordingly (3) need not be revisited in a license renewal proceeding." *AmerGen Energy Co.* (Oyster Creek Nuclear Generating Station), LBP-07-17, 66 NRC __ (Dec. 18, 2007) (slip op. at 14, n.17); *see also Turkey Point*, CLI-01-17, 54 NRC at 10 ("Issues . . . which already are the focus of ongoing regulatory processes - do not come within the NRC's safety review at the license renewal stage."). Further, "a finding of compliance of a plant with its [CLB] is not required for issuance of a renewed license." 56 Fed. Reg. at 64,951. Therefore, the CLB is only reviewed to determine whether "there is reasonable

[21] The CLB consists of "the NRC regulations contained in 10 C.F.R. parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 52, 54, 55, 70, 72, 73, 100 and appendices thereto; orders; license conditions; exemptions; and technical specifications [plus] . . . the plant-specific design-basis information [contained] . . . in the most recent final safety analysis report (FSAR) . . . and the licensee's commitments . . . [made through] responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports." 10 C.F.R. § 54.3.

assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB."[22] *See* 10 C.F.R. § 54.29(a).

The Commission's requirements regarding the adequacy of Pilgrim's program to monitor the condition of the buried pipes during the license renewal period are described in the testimony filed herewith. Specifically, as set forth in the Staff's NUREG-1891, "Safety Evaluation Report Related to the License Renewal of Pilgrim Nuclear Power Station" (Sept. 2007, Published Nov. 2007) ("SER"), the applicable legal standard for the Staff's approval of Pilgrim's program is whether Entergy has demonstrated "that the effects of aging [of Pilgrim's buried pipe and tank systems] will be adequately managed so that the intended function(s) [i.e., "delivering water"[23]] will be maintained consistent with the CLB for the period of extended operation.'" 10 C.F.R. § 54.21(a)(3). One way for a licensee to make the demonstration required by § 54.21(a)(3), is to commit to following the guidance provided by the GALL Report. Exhibit 20, SER ¶ 3.0.2 at 3-4. Entergy claimed that its four AMPs for managing the effects of aging of the two in-scope piping systems are consistent, with at most two exceptions for each, with applicable provisions of GALL. *See id.*, SER Table 3.0.3-1 at 3-8 to 3-9. Therefore, the Staff reviewed Pilgrim's program to determine consistency with GALL and, in addition, reviewed each exception to determine whether it was acceptable and whether the program, as modified, would adequately manage the effect for which it was credited. *See id.*, SER ¶¶ 3.0.2, 3.0.2.1 at 3-4 to 3-5.

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[22] As such, while this Statement of Position will be addressing inspections and tests, and operational and maintenance activities performed under Pilgrim's current license, it is not because the Staff believes such inspections, tests and activities are required as a part of an aging management review. Instead, they will be discussed as context to show Pilgrim's current monitoring systems and also to demonstrate the consistency of Pilgrim's AMPs with the CLB.

[23] Memorandum and Order (Ruling on Entergy's Motion for Reconsideration of [LPP]-07-12) (Nov. 14, 2007) (unpublished) at 4, *quoting* Entergy's Motion for Reconsideration of LPB-07-12 [sic] (Oct. 29, 2007) at 6.

II. Staff's Witnesses

The attached testimony presents the opinions of a panel of three highly qualified witnesses as follows: 1) Dr. James A. Davis, a Senior Materials Engineer in the Division of License Renewal, Office of Nuclear Reactor Regulation ("NRR"), Davis at A1; 2) Terence L. Chan, the Chief of the Piping and NDE Branch in the NRR Division of Component Integrity, Chan and Keim at A1a; and 3) Andrea T. Keim, a Materials Engineer in the NRR Division of Component Integrity, *id.* at A1b.

Dr. Davis, a metallurgical engineer, with a Doctorate in metallurgical engineering, was the audit team leader of the license renewal safety audit team at Pilgrim. Davis at A3-4. As the audit team leader, Dr. Davis led three safety audits with a team of four NRC staff members, three contractors, two NRC trainees, and one foreign assignee. *Id.* at A4. Dr. Davis reviewed portions of Entergy's LRA, including AMPs, and ensured that the remaining AMPs were adequately reviewed. *Id.* Prior to becoming a safety audit team leader, Dr. Davis was responsible for conducting reviews of coating issues, corrosion of metals, service water issues, threaded fasteners, and license renewal. *Id.* at A2. Dr. Davis has worked on coating and corrosion control since 1968, and has worked on coatings issues at nuclear facilities for the past seventeen years at the NRC. *Id.* Dr. Davis' testimony addresses the adequacy of the AMPs in place at Pilgrim to manage the effects of aging during the period of extended operation such that there is reasonable assurance that the buried piping that contains or could contain radioactive liquids will be able to perform their intended function in accordance with CLB. *Id.* at A6.

Mr. Chan, the Branch Chief for Piping and Nondestructive Examination ("NDE"), manages and provides technical review to eight engineers involved in the evaluation of generic and plant-specific materials degradation and NDE issues, American Society of Mechanical Engineers ("ASME") Code and standards activities, and inservice inspection ("ISI") activities.

Chan and Keim at A1a, A2a. Mr. Chan represents the NRC on four groups within the ASME that address materials degradation or inspection issues: Task Group on Alloy 600, Task Group on Alternate NDE, Working Group on General Requirements, and Subgroup on NDE. *Id.* at A2a. Mr. Chan's testimony will address the inspections and tests required to be performed under Entergy's current license for routine maintenance and operation of those buried pipes that are within the scope of the contention. *Id.* at A5.

Ms. Keim, a materials engineer, performs safety reviews of nuclear power plant piping and NDEs of operating nuclear power plants, license renewal applications, and new reactor design certifications. *Id.* at A1b, A2b. Ms. Keim is further responsible for conducting reviews of corrosion of metals, NDEs, risk-informed ISI programs and repair/replacement activities. *Id.* at A2b. Ms. Keim represents the NRC at ASME Section XI Code on the working group on Implementation of Risk Based Examinations. *Id.* Ms. Keim's testimony will address the inspections and tests required to be performed under Entergy's current license for routine maintenance and operation of those buried pipes that are within the scope of the contention. *Id.* at A5.

III. <u>The Concerns Raised by the Contention Lack Merit</u>

The Staff's testimony presents its position that the concerns raised by Pilgrim Watch's contention, as refined by the Board, lack merit because the AMPs alone are sufficient to manage aging such that there is reasonable assurance that the buried pipes containing, or potentially containing, radioactive liquid at Pilgrim will maintain their intended functions for the period of extended operation and will not develop leaks large enough to prevent the pipes from fulfilling their intended function. In addition, the inspections and tests performed as routine maintenance and operation provide reasonable assurance that significant leaks in the in-scope buried pipes will be detected before affecting their ability to perform their intended function. Therefore, it is not necessary to have leak detection devices or additional programs installed or in place to detect leakage in these piping systems. The bases for this position are described in detail in the testimony.

A. Buried Pipes and Tanks in Scope for Contention 1

When the Board admitted Contention 1, it limited the contention's scope "to those underground pipes and tanks that do fall within those described in 10 C.F.R. Part 54."[24] Pilgrim Watch's Contention 1 addresses only those buried pipes and tanks within the scope of license renewal "that contain radioactive liquid . . . BOTH by design and not by design."[25] There are six buried piping systems in scope for license renewal: the condensate storage ("CS") system, salt service water ("SSW") system, the standby gas service system, the fuel oil system, the station blackout diesel generator system, and the fire protection system. Davis at A7. There is only one buried tank within the scope of license renewal—the fuel oil diesel tank—and it does not contain any radioactive liquid. *Id.*

Of those buried pipes within the scope of license renewal, only one piping system, the CS system, contains radioactive water by design. *Id.* There is a small possibility that one other system, the SSW system, which contains non-radioactive cooling water, could become cross contaminated. *Id*. Neither of these systems contains buried tanks. Thus, there are no buried tanks that contain, or could contain, radioactive liquid. *Id*. Therefore, for purposes of Contention 1, the only systems that need to be addressed are the CS and SSW piping systems.

B. GALL Report

In September 2005, the NRC issued the GALL Report, which created a series of general AMPs the Staff determined are adequate to manage the aging effects of particular systems,

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[24] Memorandum and Order on Contentions at 66.

[25] Pilgrim Watch Answer Opposing Entergy's Motion for Summary Disposition of Pilgrim Watch Contention 1 (June 27, 2007) at 9.

structures and components that are subject to aging management reviews ("AMR"). Applicants may reference the GALL Report in their LRA, thus committing to the use of the generic AMP. Pilgrim's AMPs for their in-scope piping systems are consistent with the GALL Report, with minor exceptions. The Board was clear that compliance with the GALL Report was "insufficient, for the purposes of contention admissibility considerations, to overcome [] factual challenges;" however, the Board stated that it would re-consider that argument on the merits "at the appropriate stage of the proceeding."[26]

C. Condensate Storage System

1. Intended Safety Function

The CS system does not provide a credited safety function. Chan and Keim at A7. It does, however, provide the preferred supply of water to the high pressure coolant injection ("HPCI") and reactor core isolation cooling ("RCIC") systems. *Id*.

2. Routine Maintenance and Operation

There are no NRC regulations for routine maintenance and operation examinations pertaining to the CS system buried pipes, because although the CS tanks and associated piping provide the preferred water supply to the HPCI and RCIC systems, the CS system is not relied upon for accident mitigation. *Id.* at A8. However, there are tests and surveillances that would detect leaks in the buried pipes. *Id.* at A9-A10. Testing requirements for the HPCI and RCIC systems would detect leaks in the CS system. *Id.* at A9. These are required by the inservice testing ("IST") program, under 10 C.F.R. § 50.55a(f) and the technical specifications ("TS"). *Id.* Both the HPCI and RCIC systems are tested quarterly to verify flow rate and pump operability. *Id.* The test is performed by creating a flow path with suction from and discharge to the CS

[26] Memorandum and Order on Contentions at 63, n.255.

system tank. *Id.* The flow path uses the CS system buried pipes. *Id.* If there was a leak large enough to prevent water from being delivered to the pumps, the test would fail and the pumps would be declared inoperable. *Id.* This testing would allow the licensee to identify a leakage problem in the buried piping of the CS system. *Id.*

3. Aging Management Plans

The GALL Report AMP for the external surface of the CS system, XI.M34, "Buried Piping and Tanks Inspection," calls for an inspection for corrosion during maintenance that uncovers the piping, at least one inspection in the 10 years prior to the period of extended operation, and at least one more inspection in the first 10 years of the period of extended operation. Davis at A9. However, the CS system at Pilgrim contains buried stainless steel piping, which is not subject to external corrosion. *Id.* at A13. Even though corrosion is not expected, Pilgrim's AMP for external corrosion management (B.1.2. "Buried Pipes and Tanks Inspection" Program) nevertheless still complies with the GALL Report's inspection procedures. *Id*.

To minimize internal corrosion and stress corrosion cracking, Pilgrim's AMP (B.1.32.2 "Water Chemistry Control – BWR" Program), which is consistent with the GALL Report AMP (XI.Ms, "Water Chemistry"), optimizes the contaminate levels in the reactor coolant system by using hydrogen water chemistry to reduce the level of dissolved oxygen in the treated water and introduces noble metal additions to the primary water. *Id*. The effectiveness of the AMP will be verified by conducting a one-time inspection of the CS system prior to the period of extended operation, which will confirm that unacceptable cracking, loss of material, and fouling has not occurred. *Id*.

Operating history for the CS system confirms that Pilgrim's AMP for internal corrosion is effectively managing aging, above what the GALL Report guidelines suggest. Pilgrim proactively set its administrative limits more conservatively than the industry guidelines stated in the EPRI Report so that detection would occur, and corrective actions would be taken, prior to exceeding EPRI acceptance limits. *Id.* at A14. Between 1998 and 2004, several condition reports were issued for adverse trends in parameters regarding internal corrosion; however, the monitoring called for in the Water Chemistry Control – BWR Program caught the trends early and the staff was able to return the parameters to within administrative limits prior to meeting the industry limits. *Id*. Further, the Pilgrim staff in 2006 created a program basis document for review by the safety audit team that evidenced continuous monitoring of water quality and demonstrated how corrective actions would be taken before parameters reach control limits. *Id*.

D. Salt Service Water System

1. Intended Safety Function

The SSW system provides a heat sink for the reactor building closed cooling water ("RBCCW") system under transient and accident conditions. Chan and Keim at A11. Pilgrim provides assurance that the SSW will continue to perform its intended safety functions because it is designed (1) with sufficient redundancy so that no single active component failure can prevent the system from achieving its safety objective; and (2) to continuously provide a supply of cooling water to the secondary side of the RBCCW heat exchangers adequate for the requirements of the RBCCW under transient and accident conditions. *Id.* at A15.

2. Routine Maintenance and Operation

There are a number of NRC regulations that address the safety of the SSW buried piping. For instance, Generic Letter 89-13 "Service Water System Problems Affecting Safety-Related Equipment," reiterates that nuclear power plant licensees and applicants are required to meet the minimum requirements for quality assurance in 10 C.F.R. Part 50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants. *Id.* at A12. Pilgrim's FSAR demonstrates their requisite test program as required by Appendix B, Section XI, "Test Control." *Id.* at A12-13.

Applicable NRC regulations also require inspections and examinations. 10 C.F.R. § 50.55a(g) requires plants whose construction permit was issued before January 1, 1971, such as Pilgrim's, to implement an ISI program that meets 10 C.F.R. §§ 50.55a,(g)(4)-(5) to the extent practical. *Id.* at A14a. Entergy submitted its fourth 10-year ISI interval[27] program plan for Pilgrim on June 29, 2005. *Id*. The ISI program plan was developed in accordance with the requirements of the 1998 Edition of the ASME Boiler and Pressure Vessel Code, Section XI, through the 2000 Addenda ("ASME Code"), except where specific alternatives to these requirements have been authorized by the NRC. *Id*. The SSW system is included in Pilgrim's ISI program plan and will be examined and pressure tested in accordance with the requirements of the ASME Code to provide reasonable assurance of structural integrity and that significant degradation will be identified in a timely manner such that safety related systems will be able to perform their safety function. *Id*.

Pilgrim's ISI program plan referred to routine inspection, maintenance, and test requirements for the SSW system piping and heat exchanger inspections, along with the associated acceptance criteria for compliance with GL 89-13. *Id.* at A14b. These inspections are in addition to the ASME Code ISI inspections. *Id*. In the NRC's Annual Assessment Letter for Pilgrim from March 2, 2007, the regional inspector verified the heat sink performance and found nothing of significance. *Id*. The verifying of the heat sink performance provides assurance that the heat sink is capable of meeting its safety function. *Id.*

3. <u>Aging Management Plans</u>

The GALL Report has two AMPs for the SSW system: XI.M34, "Buried Piping and Tanks Inspection" ("BPTI") and XI.M20, "Open-Cycle Cooling Water System." Davis at A9. The BPTI

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[27] The fourth 10-year ISI interval runs from July 1, 2005 until June 30, 2015.

AMP calls for using preventive measures, such as the use of protective coatings, combined with the periodic inspections[28] to determine if corrosion is occurring that could affect the pressure-retaining capacity of the buried steel piping and tanks. *Id*. The Open-Cycle Cooling Water System AMP calls for testing and inspections to be conducted annually and during refueling outages to manage aging effects caused by biofouling, corrosion, erosion, internal coating failures, and silting in the open-cycle cooling water or service water system. *Id*. at A9-10.

Entergy's LRA contains two AMPs, which are consistent with the GALL Report AMPs with minor exceptions, to manage the effects of aging in the SSW system. *Id.* at A10. The first AMP is the "Buried Piping and Tanks Inspection Program," which is consistent with the GALL AMP XI.M34, "Buried Piping and Tanks Inspection" with one exception: "For cases of excavation solely for the purpose of inspection – methods such as 'phased array' ultrasonic testing ("UT") may be used to determine wall thickness without excavation." *Id*. Phased array UT uses an array of ultrasonic probes that send ultrasonic waves into the pipe at different angles to determine wall thickness, the presence of cracks, and the presence of geometric discontinuities such as laps or delaminations, which can be performed from the inside of the piping. *Id*. The Staff found this exception to be acceptable because it provided a superior method of examination than that called for in the GALL Report: it adequately searches for indications of pipe degradation yet eliminates the possibility of excavation damage to the coating during the inspection. *Id*.

The second AMP is the "Service Water Integrity Program," which is consistent with the GALL AMP XI.M20, "Open-Cycle Cooling Water System," with two exceptions. Davis at A10.

[28] Inspections will occur each time the piping is uncovered for maintenance plus at least one inspection of the coating within 10 years of the beginning of the period of extended operation and at least one inspection during the first 10 year period of extended operation. Davis at A9.

The first exception is that GALL states that systems and components are "lined or coated to protect the underlying metal surfaces from being exposed to aggressive cooling water environments." *Id*. However, at Pilgrim, components are only lined or coated where it is necessary to protect the underlying metal surfaces. *Id*. The SSW supply piping and other components that are not lined or coated are constructed using either titanium or copper alloys that are corrosion resistant in the seawater environment found in the SSW at Pilgrim. *Id*. Therefore, because it is not necessary to protect the titanium or copper alloys from the cooling water environment, the Staff found this exception to be acceptable. *Id*.

The second exception is that GALL states that the testing and inspections are performed annually, and also during the refueling outages that occur every two-years. *Id*. The Pilgrim AMP only requires testing and inspections during each refueling outage. *Id*. However, the Staff has found that adverse conditions caused by aging effects in the SSW system develop over a period of several years, and that the difference between a one-year and a two-year interval for testing and inspection is insignificant. *Id*.

Operating history for the SSW system confirms that Pilgrim is effectively managing aging, above what the GALL Report guidelines suggest. Although certain portions of the SSW piping system have experienced leaks, internal corrosion, or both, it was due to a failure of the rubber lining caused by contact with seawater. *Id.* at A11. The affected pipes have since been replaced with either titanium or carbon steel, and the entire length of both SSW discharge loops were internally lined with cured in place linings. *Id*. The Staff has found that the replacement piping and coatings are far superior to the original materials and are not expected to be affected by the contact with seawater during the period of extended operation. *Id*.

E. <u>NRC Treatment of Unexpected Leakage from Condensate Storage and Salt Service Water Systems</u>

Should any unexpected leakage occur from either the CW or SSW systems, they are treated as current operating issues. Chan and Keim at A17. Industry experience has shown that operational leakage does occur from typical service water systems as a result of corrosion due to the nature of service water environments. *Id.* Any such leakage is a nonconformance to the expected operating condition of the CS and SSW systems and are treated by NRC regulations contained in GL 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability", as revised by NRC Regulatory Issue Summary ("RIS") 2005-20, "Revision to Guidance Formerly Contained in NRC Generic Letter 91-18, 'Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability'". *Id*. Further, Appendix C, Article C.12, "Operational Leakage from Code Class 1, 2, and 3 Components," to NRC Inspection Manual Part 9900, attachment to the RIS, provides guidance for evaluating the structural integrity of the leaking component to perform its safety function and identifies actions which may be taken to determine the operability of the component. *Id.*

<u>CONCLUSION</u>

For the reasons discussed above, the AMPs alone are sufficient to manage aging of the buried pipes in the CS and SSW systems such that there is reasonable assurance that the buried pipes containing, or potentially containing, radioactive liquid at Pilgrim will maintain their intended functions for the period of extended operation and will not develop leaks large enough to prevent the pipes from fulfilling their intended purpose. In addition, the inspections and tests performed as routine maintenance and operation provide reasonable assurance that significant leaks in the in-scope buried pipes will be detected before affecting their ability to perform their intended function. Therefore, it is not necessary to have leak detection devices or additional programs installed or in place to detect leakage in these piping systems.

Respectfully submitted,

/RA/

Kimberly A. Sexton
Counsel for NRC Staff

Dated at Rockville, Maryland
this 29th day of January, 2008

January 29, 2008

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

NRC STAFF TESTIMONY OF DR. JAMES A. DAVIS
CONCERNING PILGRIM WATCH CONTENTION 1

Q1. Please state your name, occupation, and by whom you are employed.

A1. My name is James A. Davis. I am a Senior Materials Engineer in the Division of License Renewal, Office of Nuclear Reactor Regulation ("NRR"), U.S. Nuclear Regulatory Commission ("NRC"). A statement of my professional qualifications is attached hereto.

Q2. Please describe your responsibilities as a Senior Materials Engineer in the Division of License Renewal.

A2. Since November 2005, I have served as an audit team leader and as an audit team member for license renewal safety audits. Prior to joining the Division of License Renewal, I was the lead researcher on steam generator issues in the Materials Engineering Branch of the Office Nuclear Regulatory Research and a technical reviewer in the Materials and Chemical Engineering Branch of NRR, Division of Engineering. In those positions I was responsible for conducting reviews of coating issues, corrosion of metals, service water issues, threaded fasteners, and license renewal. I have worked on coatings and corrosion control since 1968 and have worked on coating issues in nuclear facilities for the past seventeen years at the NRC.

Q3. Please describe your experience relating to coatings and corrosion control.

A3. I received a Ph.D. in Metallurgical Engineering from The Ohio State University in 1968. My dissertation topic was on the initiation of stress corrosion cracks in nuclear power plant condenser tubing materials and was supported by the Atomic Energy Commission. I was the Project Manager for a joint pipeline coating research project between the Kendall Company and the All Soviet Union Oil and Gas Pipeline Institute in Moscow. I presented papers on pipeline coating at numerous technical meetings including at the annual meeting of the National Association of Corrosion Engineers ("NACE"), at the Western Canadian Meeting of NACE; for the Minister of Oil and Gas in Bagdad, Iraq; for the Minister of Oil and Gas in Cairo, Egypt; at the Australasian Corrosion Association in Adelaide, Australia as a lead speaker; at the BHRA Conference in Nice, France; and at the Tenth International Conference on Slurry Technology in Lake Tahoe, Nevada.

As part of my responsibilities at the Kendall Company, I examined the condition of pipeline coatings as a function of years of service. The general approach was to dig a "bell hole" using a backhoe to uncover the coated pipe and to take pictures of the coating to preserve the observed condition. Using the bell hole approach, I verified the condition of the coated buried piping on the Northern Border Pipeline that extended from the Canadian Border in North Dakota to Chicago, approximately every 100 miles. I also examined the coating of the 40 year old TransCanada Pipeline from Toronto to Edmonton every several hundred miles.

I have been involved in all aspects of corrosion and corrosion control including basic research, technical service, technical committee work, and preparation of sections of GALL related to corrosion and coatings. I have also authored numerous technical papers on corrosion issues. For the past 17 years while employed at the NRC I had been involved in the review of licensee submittals on stress corrosion cracking, boric acid corrosion, corrosion of service water piping, microbiological corrosion, crevice corrosion, pitting corrosion, and galvanic corrosion.

Q4. Please explain your duties in connection with the NRC staff's ("Staff") review of the License Renewal Application ("LRA") submitted by Entergy Nuclear Generation Co. and

Entergy Nuclear Operations, Inc. (collectively, "Entergy") for the renewal of the Pilgrim Nuclear Power Station ("Pilgrim").

A4. As part of my official duties during the review of Entergy's LRA, I was the safety audit team leader for the license renewal safety audit at Pilgrim. As safety audit team leader, I led three safety audits with a team of four NRC staff members, three contractors, two NRC trainees, and one foreign assignee (from the Japanese equivalent of the NRC visiting the NRC for a year) at Pilgrim. License renewal audits are divided into two teams, an environmental audit team and a safety audit team. The safety audit team audits the LRA's aging management programs ("AMP") and the application of those AMPs to manage the effects of aging during the period of extended operation. The purpose of the audit is to conduct an in-depth review of the program basis document for each AMP. The audit team members review each AMP, develop questions for the applicant's staff, discuss the questions with applicant's staff and review the applicant's response to each question. Any question that is not resolved by the end of the audit is converted to a request for additional information ("RAI"). The applicant has 30 days to provide a response to the RAI. If the question cannot be resolved, it may generate a license condition.

The first safety audit at Pilgrim was held from May 26 to 29, 2006, during which time 37 of the 38 Pilgrim AMPs were reviewed. The 38th and final AMP was reviewed by the engineering staff at NRC headquarters. I personally reviewed the following AMPs: B.1.2, "Buried Piping and Tanks Inspection"; B.1.3, "BWR Control Rod Drive Return Line Nozzle"; and B.1.4, "BWR Feedwater Nozzle" and ensured that the remaining AMPs were adequately reviewed. The second safety audit occurred from June 19 to 23, 2006, and included the same team members plus one additional NRC staff member. The purpose of the second safety audit was to audit the aging management reviews ("AMR"), which were included in the LRA that lists each system, the components in that system, the material of construction for each component, the environment that the component is exposed to, any potential aging effects for that material/component/ environment combination, and the proposed AMP to manage the effects of aging for that material/component/environment combination. A third safety audit was held from July 17 to 19, 2007, to resolve any open items from the previous audits and to conduct the Safety Audit Public Meeting to end the audit. My duties during the second and third audits were to help resolve any open items remaining from the first audit or that arose during the second and third audits.

Q5. Are you familiar with Pilgrim Watch's Contention 1, as refined by the Atomic Safety and Licensing Board ("Board")?

A5. Yes. Pilgrim Watch's Contention 1, as admitted reads:

> The Aging Management program proposed in the Pilgrim Application for license renewal is inadequate with regard to aging management of buried pipes and tanks that contain radioactively contaminated water, because it does not provide for monitoring wells that would detect leakage.

Contention 1 was clarified in the Board's Order dated October 17, 2007 as follows:

> Thus, the only issue remaining before this Licensing Board regarding Contention 1 is whether or not monitoring wells are necessary to assure that the buried pipes and tanks at issue will continue to perform their safety function during the renewal period – or, put another way, whether Pilgrim's existing AMPS have elements that provide appropriate assurance as required under relevant NRC regulations that buried pipes and tanks will not develop leaks so great as to cause those pipes and tanks to be unable to perform their intended safety functions.

Q6. What is the purpose of your testimony?

A6. My testimony will address the adequacy of AMPs in place at Pilgrim to manage the effects of aging during the period of extended operation such that there is reasonable assurance that the buried piping that contains or could contain radioactive liquids will be able to perform their intended function in accordance with the current licensing basis ("CLB").

Q7. Are there buried pipes and tanks for systems within the scope of license renewal that could contain radioactive liquids?

A7. There are buried pipes, but no buried tanks, within scope that could contain radioactive liquids.

The buried piping in scope for license renewal are part of the following systems: the condensate storage ("CS") system, salt service water ("SSW") system, the standby gas service system, the fuel oil system, the station blackout diesel generator system, and the fire protection system. The only system that contains radioactive liquid by design is the CS system, which contains buried piping, but no buried tanks. The SSW system is designed to contain non-radioactive cooling water. However, the SSW system cools the reactor building closed-cooling water system, which cools systems that contain radioactive water. Thus, there is a possibility that the SSW could become cross contaminated. The SSW system contains buried piping but no buried tanks.

The standby gas treatment system could contain radioactive gas following an accident, but would not contain radioactive liquid.

The only tank in scope for license renewal is the fuel oil diesel tank and it does not contain any radioactive liquid.

The station blackout diesel generator system and the fire protection system do not contain any radioactive liquids.

Q8. Are you familiar with the Generic Aging Lessons Learned ("GALL") Report?

A8. Yes. The GALL Report contains Staff developed guidance for AMPs and AMRs that the Staff finds acceptable for controlling the effects of aging for the period of extended operation. Generic Aging Lessons Learned Report, NUREG-1801, Vol. 2, Rev. 1 (Sept. 2005). The GALL report was developed by the Staff and repeatedly reviewed by the Nuclear Energy Institute ("NEI") and the nuclear industry during its development. The GALL Report was published in the Federal Register to allow the public or any interested parties the opportunity to make public comments on the GALL Report. After the public comments were resolved, the report was published.

Q9. What does the GALL Report require for the SSW buried piping?

A9. The GALL AMPs for SSW include XI.M34, "Buried Piping and Tanks Inspection," ("BPTI"), (Staff Ex. 1), and XI.M20, "Open-Cycle Cooling Water System" (Staff Ex. 2). The BPTI AMP calls for using preventive measures to mitigate corrosion and periodic inspections to determine if corrosion is occurring that could affect the pressure-retaining capacity of the buried steel piping and tanks. The preventive measures to mitigate corrosion involve the use of protective coatings combined with the periodic inspections. Corrosion can occur as a result of exposure to an aggressive soil environment. The four relevant aging effects are general, pitting, crevice corrosion, and microbiologically-influenced corrosion ("MIC"). Inspections are to be conducted each time the piping is uncovered for maintenance. For example, the coating and external surface of two 40-foot sections of piping on the discharge loops were examined in 1999 when the two 40-foot sections were replaced. The coatings were found to be in good condition and no external corrosion was noted. Those coatings were then removed to inspect the outside surface of the piping which was also found to be in good condition.

The BPTI AMP requires that at least two inspections of the coating take place: one within 10 years prior to the period of extended operation and at least one inspection during the first 10 year period of extended operation.

The Open-Cycle Cooling Water System AMP was generated in response to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Components," (July 18, 1989). (Staff Ex. 3). This program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, internal coating failures, and silting in the open-cycle cooling water or service water system. (Staff Ex. 2 at XI M-72). This AMP addresses aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms. *Id.* The guidance in Generic Letter 89-13 includes surveillance and control of biofouling; a test program to verify heat transfer capabilities; a routine inspection and maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of safety-related systems serviced by the open-cycle cooling system; a system walk down inspection to ensure compliance with the licensing basis; and a review of maintenance, operating and training practices and procedures. *Id.* Testing and inspections are conducted annually and during refueling outages. The five specific recommended actions in Generic Letter 89-13 are: I) For open-cycle service water systems, implement and maintain an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling; II) Conduct a test program to verify the heat transfer capability of all safety-related heat exchangers cooled by service water; III) Ensure by establishing a routine inspection and maintenance program for open-cycle service water system piping and components that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of safety-related systems supplied by service water; IV) Confirm that the service water system will perform its intended function in accordance with the licensing basis for the plant, including a review of the ability to perform required safety functions in the event of failure of a single active component; and, V) Confirm that maintenance practices, operating and emergency procedures, and training that involves service water are adequate to ensure that safety-related equipment cooled by the service water system will function as intended and that operators of this equipment will perform effectively. (Staff Ex. 3 at 4-6).

Generic Letter 89-13 contains as an enclosure the Recommended Program to Resolve Generic Issue 51, which describes a program that is acceptable to the NRC staff for meeting the objectives of the requested Action I in the generic letter. (Staff Ex. 3, Enclosure 1). For a plant like Pilgrim that uses marine water in the service water system, the program recommends: A) The intake structure should be visually inspected, once per refueling cycle, for macroscopic biological organisms such as blue mussels, sediment, and corrosion. Inspections should be performed either by scuba divers or by dewatering the intake structure or by other comparable methods. Any fouling accumulations should be removed; B) the service water system should be continuously chlorinated or injected with effective biocides whenever the potential for a microscopic biological fouling species exists; and C) Redundant and infrequently used cooling loops should be flushed and flow tested periodically at the maximum design flow to ensure that they are not fouled or clogged. (Staff Ex. 3, Enclosure 1 at 1-2). In addition, another enclosure gives an acceptable program for testing of heat exchangers. (Staff Ex. 3, Enclosure 2).

Q10. Which AMPs does Pilgrim use for the SSW system?

A10. There are two AMPs for the SSW system piping. The first AMP is the "Buried Piping and Tanks Inspection Program" (Staff Ex. 4, LRA § B.1.2 at B-17). This Pilgrim AMP is consistent with the GALL XI.M34, "Buried Piping and Tanks Inspection," with one exception. The exception cited by Pilgrim is: "For cases of excavation solely for the purpose of inspection – methods such as 'phased array' UT (ultrasonic testing) may be used to determine wall thickness without excavation." Phased array UT test uses an array of ultrasonic probes that send ultrasonic waves into the pipe at different angles to determine wall thickness, the presence of cracks, and the presence of geometric discontinuities such as laps or delaminations. This kind of inspection can be performed from the inside of the piping. The staff found this exception to be acceptable because it would adequately search for indications of pipe degradation yet eliminate the possibility of excavation damage to the coating during the inspection. Similar methods are commonly used in the oil and gas industry for inspecting their buried piping.

Pilgrim's second program is the "Service Water Integrity Program" (Staff Ex. 5, LRA § B.1.28 at B-92). This program is consistent with the GALL XI.M20, "Open-Cycle Cooling Water System," with two exceptions. The first exception is that while GALL states that all systems and components are lined or coated, at Pilgrim, components are only lined or coated where it is necessary to protect the underlying metal surfaces. The SSW supply piping that is not lined is constructed using titanium, which is not susceptible to corrosion in seawater environments such as that found in the SSW at Pilgrim. The other components in the SSW supply that are not coated or lined are small-bore piping for vents and drains, pump and valve bodies, and heat exchanger tubes. All of these components are constructed using copper alloys that are also corrosion resistant in Pilgrim's environment. During the safety audit at Pilgrim, the staff found this exception to GALL to be acceptable for service water piping (Staff Ex. 6, SER at 3-94). GALL states that "The system components are constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from being exposed to aggressive cooling water environments." Titanium and copper alloys are not susceptible to corrosion by salt water, and hence, the Staff agrees that lining the pipes constructed using titanium or copper alloys is not necessary.

The second exception is that GALL states that the testing and inspections are performed annually, and during refueling outages, which are on a two-year frequency. The Pilgrim program only requires testing and inspections during each refueling outage. During the safety audit, the Staff evaluated Pilgrim's testing and inspection interval and agreed that because adverse conditions caused by aging effects in the salt service water system develop over a period of several years, the difference between a one-year and a two-year interval for testing and inspection is insignificant.

Q11. What is the operating history for Pilgrim's SSW buried piping?

A11. The SSW system has had leaks in the buried inlet piping due to internal corrosion. The inlet piping ran from the screenhouse to the auxiliary bays. The original piping material was internally rubber-lined carbon steel piping that was coated externally with coal tar enamel. The coal tar enamel coating is applied as follows: 1) the external surface is cleaned until free of loose mill scale, rust, corrosion products, dirt, grease, moisture, or other foreign material; 2) grease or heavy oil is removed by a suitable solvent; 3) a layer of primer is applied to the surface; 4) a 3/32 inch thick layer of coal tar enamel is applied; 5) fiberglass pipe wrap is applied while the coal tar enamel is still liquid in a spiral fashion with between ½ and one inch of overlap; 6) an additional 1/16 inch of coal tar enamel is applied over the fiberglass pipe wrap; 7) an asbestos felt saturated with coal tar enamel is applied over the final layer of coal tar enamel; and 8) a layer of heavy Kraft paper is applied in a spiral wrap over the entire coating system with between ½ and one inch of overlap. The coating is inspected for voids or holidays (defects in the coating that exposes bare metal) in the field using a high voltage holiday detector. (Entergy Ex. 3). The rubber lining had degraded from being in contact with the sea water. These pipes were replaced in 1995 and 1997 with titanium pipe coated with the same external coating as was installed on the original pipe, as described above.

The SSW buried discharge piping from the auxiliary bays to the discharge canal experienced severe internal corrosion. This piping had the same external and internal coatings as the inlet piping, and again, the corrosion was caused by the failure of the rubber lining in contact with the seawater. Two 40-foot lengths of 22-inch diameter pipes were replaced in 1999 with carbon steel coated internally and externally with epoxy: one in “A” Loop and one in “B” Loop. The whole length of both SSW discharge loops were internally lined with cured in place linings: the “B” loop in 2001, and the “A” Loop in 2003. Based on my experience with these coatings and linings, I consider the replacement piping and coatings to be far superior to the original materials and coatings and are expected not to be affected by the contact with seawater for the period of extended operation. Also, any degradation would be detected by the inspections and testing before the systems are not able to perform their intended function.

Q12. Does Pilgrim have any special requirements for handling buried piping?

A12. Yes. Lifting of the pipe shall be with wide, non abrasive canvas or leather belts, or other equipment designed to prevent damage to the pipe. *Id*. Controlled backfill that is properly compacted will be used under and around the buried pipe. (Staff Ex. 7, PDC No. 99-21). The use of controlled backfill greatly reduces the probability of damage to the coating. Uncontrolled backfill can contain rocks that can damage the coating.

Q13. How do the AMPs address the CS system?

A13. The CS system contains buried stainless steel piping. The LRA states that external corrosion of this piping will be managed by using the B.1.2 “Buried Piping and Tanks Inspection” Program, which is consistent with GALL AMP XI.M34, “Buried Piping and Tanks Inspection”. Stainless steel piping is not subject to external corrosion by contact with soil.

Nonetheless, even though corrosion is not anticipated, the external surface of the CS system piping is coated with the coal tar enamel coating system and will be inspected during maintenance that uncovers the piping.

Internal corrosion of this piping will be managed using B.1.32.2 “Water Chemistry Control – BWR” Program, which is consistent with GALL AMP XI.M2, “Water Chemistry.” The Water Chemistry Control – BWR Program optimizes the contaminate levels in the reactor coolant system to minimize potential loss of material and cracking. Pilgrim has started using hydrogen water chemistry to limit the potential for intergranular stress corrosion cracking by reducing the level of dissolved oxygen in the treated water. In addition, Pilgrim has introduced noble metal additions to the primary water which has been shown to be effective in eliminating primary water stress corrosion cracking. (Staff Ex. 8 at 3-34). The effectiveness of the Water Chemistry Control – BWR Program will be verified by conducting a one-time inspection of the CS system prior to the period of extended operation. The one-time inspection will confirm that unacceptable cracking, loss of material, and fouling has not occurred. (Staff Ex. 9, SER at 3-26 - 29).

Q14. What is the operating history for the CS system at Pilgrim?

A14. From 1998 through 2004, several condition reports were issued by Pilgrim for adverse trends in parameters monitored by the Water Chemistry Control – BWR Program. The Pilgrim staff took appropriate actions to return the parameters to within administrative limits. Although the parameters had exceeded administrative limits, they had not exceeded the EPRI acceptance limits which had been established by agreement between the EPRI staff and industry experts. The administrative limits had been set by the staff at Pilgrim to be below the EPRI acceptance limits, so that the administrative limits could be exceeded for a short time and corrective actions could be taken before the EPRI acceptance limits had been exceeded. For example, following a power outage on March 29, 2002, the dissolved oxygen measurement from the B high-pressure train was about 28 parts per billion (ppb), which is below the minimum reading of 30 ppb (the EPRI action level 1). The dissolved oxygen measured in the A high-pressure train and condensate demineralizer effluent were acceptable at about 70 and 80 ppb. The root cause was found to be that the B high-pressure sample line was defective and was replaced. A second example occurred on October 28, 2002, when the high-pressure train and the condensate demineralizer effluent dissolved oxygen levels spiked to between 400 and 500 ppb for about 15 minutes before returning to normal. The EPRI action level 1 for the high-pressure train is 200 ppb. The root cause was inadequate filling of the demineralizer prior to return to service. Procedural steps were emphasized for proper venting to mitigate elevated oxygen levels in the feedwater system. This gives additional assurance that undesirable aging would not occur. During the 2006 safety audits at Pilgrim, the Pilgrim Staff provided a program basis document for review by the audit team. This document pointed out the continuous monitoring of water quality and demonstrated how corrective actions would be taken before parameters reach control limits, thus providing evidence that the program effectively manages component aging effects. (Staff Ex. 8 SER 3-35).

Q15. Are there any leak detection devices required to meet the requirements of 10 C.F.R. Part 54?

A15. No. 10 C.F.R. Part 54 does not specify any leak detection devices for use in AMPs for buried pipes and tanks. In addition, there are no leak detection devices recommended in GALL AMP XI.M34, “Buried Piping and Tanks Inspection.”

Q16. Can the standby gas treatment system contain radioactive liquid?

A16. The standby gas treatment system limits the release of radioactive material to the environs from a postulated design-basis accident. The standby gas treatment system is part of the secondary containment system, which provides secondary containment for postulated loss-of-coolant-accidents and primary containment for postulated refueling accidents. The standby gas treatment system consists of two full-capacity trains with dampers, an exhaust fan, and an air filtration assembly. The standby gas treatment system shares ducting with the various reactor building exhaust systems and can draw air from the reactor building clean and contaminated compartment exhausts, the refueling floor exhaust, the drywell, and suppression pool exhausts. After treatment, the air is discharged through a line of the underground vent duct system consisting of ducts, dampers, pipes, valves, and the 20-inch underground vent, which transports gaseous effluent from the standby gas treatment system to the primary containment atmospheric control system to the main stack. It does not contain any water and therefore, is not the subject of Contention 1.

Q17. What is the Staff's conclusion regarding whether the AMPs for buried pipes are adequate to detect leaks to ensure that safety function challenging leaks will not occur in the buried pipes at Pilgrim?

A17. The buried piping at Pilgrim that could potentially contain radioactive liquid has either been replaced or has not experienced external or internal degradation. In addition, aging of buried piping at Pilgrim is effectively managed by the Buried Piping and Tanks Inspection Program for the external surfaces, by the Service Water Integrity Program for SSW piping, and by the Water Chemistry Control – BWR Program and One-Time Inspection Program for the CS piping. As described in detail above, these AMPs provide reasonable assurance that the buried piping containing or potentially containing radioactive liquid at Pilgrim will not develop leaks so great as to prevent them from performing their intended safety function and they will maintain their intended functions for the period of extended operation. For these reasons, these AMPs are adequate as they are and no leak detection devices are required.

Q19. Does this conclude your testimony?

A19. Yes.

<u>James A. Davis, Ph.D</u>
Statement of Professional Qualifications

<u>CURRENT POSITION:</u>

Senior Materials Engineer	Division of License Renewal, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Rockville, MD

<u>EDUCATION:</u>

B. Met. E., The Ohio State University, 1965, Metallurgical Engineering
M.S., The Ohio State University, 1965, Metallurgical Engineering
Ph.D., The Ohio State University, 1968, Metallurgical Engineering

<u>SUMMARY:</u>

Over 39 years of experience in materials engineering with over 20 years of experience in the nuclear power industry. Significant experience in the following areas:

- Materials Engineering
- Corrosion and Control
- Protective Coatings and Linings
- Welding and Special Repair Processes
- License Renewal
- Nuclear Facilities Audits
- Allegations
- Reviews of Navy Submarine Power Plant Designs
- Quality Assurance
- American Society of Mechanical Engineers (ASME) Code Committees
- American Society for Testing and Materials (ASTM) D-33 Committee on Coatings for Power Generation Facilities

<u>EXPERIENCE:</u>

<u>U.S. Nuclear Regulatory Commission, 11/11/1990 – Present</u>

11/13/2005 to 12/31/2007 – Senior Materials Engineer, Division of License Renewal, Office of Nuclear Reactor Regulation

- Audit Team Leader for the license renewal safety audit at the Indian Point Nuclear Power Plant

- Backup Audit Team Leader for the license renewal safety audit at the Wolf Creek Generating Station

- Audit Team Leader for the license renewal safety audit at the Pilgrim Nuclear Power Station

- Audit Team Member for the license renewal safety audit at the Oyster Creek Generating Station

12/15/2001 - 11/13/ 2005 – Senior Materials Engineer, Division of Engineering Technology, Office of Nuclear Regulatory Research

- Program Manager on the Steam Generator Tube Integrity Program overseeing work conducted at Argonne National Laboratory

- Acting Program Manager for Non-Destructive Examination research at Pacific Northwest National Laboratory

11/11/1990 - 12/15/2001 – Materials Engineer, Chemical Engineering and Metallurgy Section, Materials and Chemical Engineering Branch, Division of Engineering, Office of Nuclear Reactor Regulation

- ASTM Committee member for Coatings for nuclear power plants

- Lead reviewer for auxiliary systems for license renewal for Calvert Cliffs, Oconee, Arkansas Nuclear One, Hatch, and Turkey Point

- Responsible for all threaded fastener issues (such as stress corrosion cracking, boric acid corrosion, and fatigue)

- Lead reviewer for full system chemical decontamination at Indian Point

- Lead reviewer for Boiling Water Reactor internals cracking

- Lead reviewer for pump and valve internals cracking

- Lead reviewer for pipe integrity issues

- Assisted the Spent Fuel Program Office in the review of corrosion behavior for dry cask storage and interaction of coatings with spent fuel water

- Coordinated the responses to a generic letter on containment coatings for nuclear power plants

- NRC representative to ASTM D-33 on coatings for power generation facilities

- Member of the Board of Directors for the National Board of Registration for Nuclear Safety Related Coating Engineers & Specialists

- Member of ASME on Welding and Special Repair Processes

- Member of an Augmented Inspection Team at Palisades on fuel handling problems

- Member of the Augmented Inspection Team at Point Beach on the hydrogen burn as a result of interactions between borated water and the inorganic zinc coating during dry cask loading operations

- Member of the Augmented Inspection Team at Davis-Besse on the boric acid corrosion of the vessel head.

- Contract Technical Monitor and Project Officer for numerous contracts at Brookhaven National Labs

- Technical reviewer for the design of the Navy Seawolf Submarine and the Virginia Class Submarine

- Reviewer on the Department of Energy (“DOE”) project to produce tritium in a commercial reactor (Watts Bar)

- Numerous presentations to senior NRC management including the Chairman, the Executive Director for Operations, the Committee to Resolve Generic Issues, and the Advisory Committee on Reactor Safety and Safeguards

- Testified before Representative Dingle’s staff on the safety of fasteners in nuclear power plants as a result of concerns raised by a private citizen. Convinced Representative Dingle’s staff that there is no safety issue because of the redundant design of mechanical joints, the fact that the joints will leak before they break, and that the joints are inspected every refueling outage.

Polyken Division of the Kendall Company, Senior Research Associate, 1981 – 1990:

- Responsible for Technical Marketing for the pipeline coating division providing technical data and reports to domestic and international customers

- Company representative to the National Association of Corrosion Engineers, the American Water Works Association coatings committees, and ASTM coating committees

Arthur D. Little, Senior Consultant, 1979 - 1981:

- Consultant to DOE on Defense Nuclear Waste and Waste Tank corrosion issues
- Consultant on numerous commercial contracts on corrosion, coating, metallurgical, and plating issues

Allied Tube and Conduit Corp., Director of Research, 1978-1979:

- Responsible for research and development for metallurgical tube forming, welding, chemical cleaning of steel, galvanizing, surface treatment and coating of electrical conduit, fence posts, and specialty tubing
- Responsible for Quality Assurance and Process Control Departments

Allegheny Ludlum Steel Corp., Research Specialist, 1976-1978:

- Responsible for customer service for use of stainless steels in corrosive service
- Responsible for conducting failure analyses
- Conducted research on corrosion mechanisms for stainless steels

Bell Aerospace Company, Senior Research Scientist, 1970-1976:

- Program Manager on numerous Navy sponsored programs involving corrosion of aluminum alloys, stainless steels, and titanium alloys in high velocity sea water for the Navy's high performance ships program
- Conducted research on corrosion fatigue, stress corrosion, and fouling in sea water
- Conducted research on the compatibility of rocket fuels and oxidizers with fuel handling equipment

U.S. Steel Corporation, Senior Research Engineer, 1968-1970:

- Conducted research on the mechanism of pitting/crevice corrosion, stress corrosion cracking, hydrogen embrittlement, and intergranular corrosion using electrochemical techniques, transmission electron microscopy, optical microscopy, and scanning electron microscopy

PUBLICATIONS-PRESENTATIONS:

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2. J. A. Davis, "Resistance of 18 Cr-18Ni-2Si Stainless Steel to Stress Corrosion Crack Propagation in Boiling magnesium Chloride" Corrosion, Vol. 26, No. 3, 1970

3. J. A. Davis and B. E. Wilde, "Electrochemical Measurements on Austenitic Stainless Steels in Boiling Magnesium Chloride," Jnl. Electrochemical Soc., Vol. 117, No. 11, November, 1970, p 1348-1351

4. J. A. Davis, A. A. Staklis, and A. A. Watts, "Potential and pH Measurements During Stress Corrosion of Some Metallic Alloys," Presented at Corr/71, Research in Progress, Chicago, Ill. Mar., 1971

5. J. A. Davis, A. A. Staklis, and A. A. Watts, "Potential and pH Changes During Stress Corrosion of Some Metallic Alloys," Institute of Environmental Sciences Proceedings, 7th Annual Conference, Living in Our Environment, Los Angeles, California, Apr 26-30, 1971, p 117-122

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7. J. A. Davis and G. A. Gehring, Jr., "The Effect of Velocity on the Sea Water Corrosion Behavior of High Performance Ship Materials," Corr/74 International Corrosion forum, Paper 78, Mar 4-8, 1974, Houston, Tx p78/1-78/17

8. J. A. Davis, "Use of Miscroelectrodes for Study of Stress Corrosion of Aluminum Alloys," International Conference on Localized Corrosion, Williamsburg, Va., NACE No. 3, 1974, p32-39

9. J. A. Davis and G. A. Gejring, Jr., "The Effect of Velocity on the Sea Water Corrosion Behavior of High Performance Ship Materials," Materials Performance, Vol 14, No. 4, 1974, p 32-39

10. J. A. Davis, A. A. Watts and G. A. Gehring, Jr., "Pitting Behavior of Aluminum Alloys in High Velocity Sea Water," Presented at the annual Conference of the Electrochemical Society, Las Vegas, Nevada, Oct 18-22, 1976

11. T. J. Nichol and J. A. Davis, "Intergranular Corrosion Testing and Sensitization of Two High-Chromium Ferritic Stainless Steels," ASTM Spec. Tech. Publication STP 656, Intergranular Corrosion of Stainless Alloys, May 2-3, 1977, p179-196

12. R. A. Lula and J. A. Davis, "Intergranular Corrosion in 12 Chromium Ferritic Stainless Steels," ASTM Spec. Tech. Publication STP 656, Intergranular Corrosion of Stainless Steels, May 2-3, 1977, p233-247

13. J. A. Davis and M. J. Johnson, "The Effect of Temperature on the Pitting Behavior of High Performance Stainless Steels," Presented at Corr/78, Chicago, Ill., Mar., 1978

14. J. A. Davis, H. E. Deverell and M. J. Johnson, "Comparison of Stainless Steels with Cooper Nickel Alloys in Polluted Seawater," presented at Corr/78, Chicago, Ill., Mar. 1978

15. J. A. Davis and M. J. Johnson, "Corrosion Characteristic of Stainless Steels," Presented at the Pittsburgh Section of ASM Sept., 1978

16. J. A. Davis, "Stabilization of High Chromium Ferritic Stainless Steels," Presented at the Annual Meeting of the Electrochemical Society, Seattle, Washington, Oct., 1978

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20. J. A. Davis, "Performance of Polyethylene Tape Coated Pipelines for Underground Service," Shreveport, La, NACE, July 6, 1982

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22. J. A. Davis, "Performance of Polyethylene Coated Pipelines with Underground Burial," NACE Eastern Canadian Regional Conference, November 23-25, 1982, Montreal, Quebec

23. J. A. Davis, "Performance of Polyethylene coated Pipelines With Underground Burial," Proceedings of the Australian Pipeline Industry Association Annual Conference, Camberra, New South Wales, Australia, Nov., 1983

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

PREFILED TESTIMONY OF DR. JAMES A. DAVIS

I, James A. Davis, do declare under penalty of perjury that my statements in the foregoing testimony and my attached statement of professional qualifications are true and correct to the best of my knowledge and belief.

/Original Signed By/
____
James A. Davis

Executed at Rockville, Maryland
This 29th day of January, 2008.

January 29, 2008

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NRC STAFF TESTIMONY OF TERENCE L. CHAN AND ANDREA T. KEIM
CONCERNING PILGRIM WATCH CONTENTION 1

Q1. Please state your name, occupation, and by whom you are employed.

A1a. My name is Terence L. Chan (TLC). I am employed as Branch Chief of the Piping and Nondestructive Examination ("NDE") Branch within the Division of Component Integrity, Office of Nuclear Reactor Regulation ("NRR"), U.S. Nuclear Regulatory Commission ("NRC"). A statement of my professional qualifications is attached hereto.

A1b. My name is Andrea T. Keim (ATK). I am a Materials Engineer in the Division of Component Integrity, NRR, NRC. A statement of my professional qualifications is attached hereto.

Q2. Please describe your current responsibilities.

A2a. (TLC) As Chief of the Piping and NDE Branch since 2001, I manage eight engineers involved in the evaluation of generic and plant-specific materials degradation and NDE issues, American Society of Mechanical Engineers ("ASME") Code and standards activities, and inservice inspection ("ISI") activities. My branch is also involved in the review of certain power uprate and license renewal applications, and provides technical support to the regional offices. I provide day-to-day management of activities in my branch, which include administrative and technical review responsibilities. As part of my duties, I represent the NRC on four groups within the ASME that address materials degradation or inspection issues: Task Group on Alloy 600, Task Group on Alternate NDE, Working Group on General Requirements, and Subgroup on NDE.

A2b. (ATK) I am responsible for performing safety reviews related to nuclear power plant piping and NDEs of operating nuclear power plants, license renewal applications, and new reactor design certifications. For the past twelve years, I have reviewed plant license and license renewal applications and have been involved in updating technical review guidance documents, such as standard review plans. As a technical reviewer in the Division of Component Integrity, I have been responsible for conducting reviews involving corrosion of metals, NDEs, risk-informed ISI programs and repair/replacement activities. I represent the NRC at the ASME Section XI Code on the working group on Implementation of Risk Based Examinations.

Q3. Please explain your duties in connection with the NRC staff's ("Staff") review of the License Renewal Application ("LRA") submitted by Entergy Nuclear Generation Co. and Entergy Nuclear Operations, Inc. (collectively, "Entergy") for the renewal of the Pilgrim Nuclear Power Station ("Pilgrim").

A3. (TLC) (ATK) We were not involved in the review of Entergy's LRA.

Q4. Are you familiar with Pilgrim Watch's Contention 1, as refined by the Atomic Safety and Licensing Board ("Board")?

A4. (TLC) (ATK) Yes. Pilgrim Watch's Contention 1, as admitted reads:

> The Aging Management program proposed in the Pilgrim Application for license renewal is inadequate with regard to aging management of buried pipes and tanks that contain radioactively contaminated water, because it does not provide for monitoring wells that would detect leakage.

Contention 1 was clarified in the Board's Order dated October 17, 2007 as follows:

> Thus, the only issue remaining before this Licensing Board regarding Contention 1 is whether or not monitoring wells are necessary to assure that the buried pipes and tanks at issue will

> continue to perform their safety function during the renewal period – or, put another way, whether Pilgrim's existing AMPS have elements that provide appropriate assurance as required under relevant NRC regulations that buried pipes and tanks will not develop leaks so great as to cause those pipes and tanks to be unable to perform their intended safety functions.

Q5. What is the purpose of your testimony?

A5. (TLC) (ATK) Our testimony will address the required tests and inspections being performed under Pilgrim's current license for routine maintenance and operation of those buried pipes and tanks within the scope of the contention.

Q6. Are there buried pipes and tanks for systems within the scope of license renewal that could contain radioactive liquids?

A6. (TLC) (ATK) Yes, with respect to buried pipes, but there are no buried tanks within the scope of Contention 1. According to the testimony of James A. Davis, PhD., the buried piping in scope for Entergy's license renewal application are part of the following systems: the condensate storage ("CS") system, salt service water ("SSW") system, the standby gas service system, the fuel oil system, the station blackout diesel generator system, and the fire protection system. The only system that contains radioactive liquid by design is the CS system, which contains buried piping but no buried tanks. The SSW system is designed to contain non-radioactive cooling water. However, the SSW system cools the reactor building closed cooling water ("RBCCW") system, which cools systems that contain radioactive water. Thus, there is a small possibility that the SSW could become cross contaminated. The SSW system contains buried piping but no buried tanks.

The standby gas treatment system could contain radioactive gas following an accident, but would not contain radioactive liquid.

The only buried tank in scope for license renewal is the fuel oil diesel tank and it does not contain any radioactive liquid.

The station blackout diesel generator system and the fire protection system do not contain any radioactive liquids.

These systems are consistent with those discussed in the Applicant's testimony dated January 8, 2008.[1]

Q7. What is the intended function of the CS system?

A7. The CS system does not provide a credited safety function. It does however provide the preferred supply of water to the high pressure coolant injection ("HPCI") and reactor core isolation cooling ("RCIC") systems.

The RCIC system provides makeup water to the reactor vessel whenever the vessel is isolated. The HPCI system provides and maintains coolant inside the reactor vessel to prevent fuel clad melting in the event of a postulated small break in the reactor coolant system.

Q8. What inspection or examinations are required by current NRC regulations or Pilgrim's technical specifications for the CS system?

A8. (TLC) The CS system provides for condensate system makeup and system rejection to accommodate fluctuations in power generation demands. Although the CS tanks and associated piping provide the preferred water supply to the HPCI and RCIC systems, the CS system is not relied upon for accident mitigation. The torus water storage provides the backup emergency HPCI and RCIC systems water supply. As such, there are no inspections or examinations of the CS system required by the NRC regulations or technical specifications.

Q9. Are there any requirements that would detect leaks in the CS system buried pipes?

A9. (ATK) Yes. There are testing requirements for the RCIC and HPCI systems that would allow the licensee to identify a leakage problem in the buried piping of the CS system.

[1] Testimony of Alan Cox, Brian Sullivan, Steve Woods, and William Spatero 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 (January 8, 2008), at 9, 13-15

The regulations at 10 C.F.R. § 50.55a(f) require plants whose construction permit was issued before January 1, 1971, such as Pilgrim's, to implement an Inservice Testing ("IST") program that meets 10 C.F.R. §§ 50.55a(f)(4)-(5) to the extent practical.

By letter dated December 6, 2002, the licensee submitted the fourth 10-year IST program plan for Pilgrim. (Staff Ex. 10). The fourth 10-year IST interval started on December 7, 2002 and ends December 7, 2012. The IST program plan was developed in accordance with the requirements of the 1995 Edition through the 1996 Addenda of the ASME Code for Operation and Maintenance of Nuclear Power Plants, except where specific alternatives to these requirements have been authorized by the NRC.

In accordance with the Pilgrim IST program and the Pilgrim technical specifications, specifically Surveillance Requirement 4.5.C. for the HPCI system and Surveillance Requirement 4.5.D. for the RCIC system (Staff Ex. 11), the HPCI system and the RCIC system are tested quarterly to verify flow rate and pump operability. (Staff Ex. 10 at 17 of 179, 18 of 179). The test for HPCI and RCIC pumps are performed by establishing a flow path with suction from and discharge to the condensate storage tank. This suction path utilizes the buried piping from the condensate storage tank to the HPCI and RCIC pump suctions as identified by the Pilgrim January 8, 2008 testimony. Entergy's Testimony at 13-14, 15) A leak large enough to prevent condensate storage tank water delivery to these pumps would cause the quarterly IST to fail and the tested pumps would be termed inoperable. This would require Pilgrim to take action pursuant to the TSs. The testing would allow the licensee to identify a leakage problem in the buried piping of the CS system.

Q10. How does Pilgrim's FSAR address the CS system?

A10. (ATK) FSAR 11.9 discusses the power generation objective of the condensate storage system at Pilgrim. (Staff Ex. 12) As discussed above, the CS system provides the preferred supply of water to the HPCI and RCIC systems. The torus water storage provides the backup emergency HPCI and RCIC systems supply. There are two 275,000 gallon CS tanks that are above ground. The tanks are made of coated carbon steel with all inlet and outlet lines, overflows, vents, and instrument lines located at the tank bottom or toward the tank center to prevent freezing problems. All systems that take suction from the condensate storage tanks are located above the HPCI and RCIC suctions to provide a 75,000 gallon reserve in each tank for these systems.

Q11. What is the intended safety function of the SSW system?

A11. (ATK) The SSW system provides a heat sink for the RBCCW system under transient and accident conditions.

Q12. What current NRC regulations address the safety of buried piping in the SSW system at Pilgrim?

A12. (ATK) On July 18, 1989, the NRC issued Generic Letter ("GL") 89-13, "Service Water System Problems Affecting Safety-Related Equipment," after operating experience and studies led the Staff to question the compliance of service water systems in the nuclear power plants of licensees and applicants with certain general design criteria ("GDC") and quality assurance requirements. (Staff Ex. 3).

As addressed in the purpose section of GL 89-13, nuclear power plant facilities or licensees and applicants must meet the minimum requirements for quality assurance in 10 C.F.R. Part 50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants. In particular, Section XI, "Test Control," requires that "a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents."

Q13. Has Pilgrim established a test program as required by Appendix B?

A13. (ATK) Yes, as stated in FSAR Section 1.10. (Staff Ex. 13).

Q14. What inspection or examinations are required by NRC regulations for the SSW System?

A14a. (TLC) The regulations at 10 C.F.R. § 50.55a(g) require plants whose construction permit was issued before January 1, 1971, such as Pilgrim's, to implement an ISI program that meets 10 C.F.R. §§ 50.55a(g)(4)-(5) to the extent practical.

By letter dated June 29, 2005, the licensee submitted the fourth 10-year ISI program plan for Pilgrim. (Staff Ex. 14). The fourth 10-year ISI interval started on July 1, 2005 and ends June 30, 2015. The ISI program plan was developed in accordance with the requirements of the 1998 Edition of the ASME Boiler and Pressure Vessel Code (Code), Section XI, through the 2000 Addenda, except where specific alternatives to these requirements have been authorized by the NRC. The SSW system is included in Pilgrim's ISI Program Plan and will be examined and pressure tested in accordance with the requirements of the ASME Code, Section XI and Pilgrim's augmented ISI requirements. (*Id.* at 1-11, 1-14, 1-15). In 10 C.F.R. § 50.55a(b) the NRC has approved the use of Section XI of the ASME Code including the 1970 Edition through the 1976 Winter Addenda, and the 1977 Edition through the 2003 Addenda, subject to certain limitations and modifications stated in 10 C.F.R. § 50.55a(b)(2). Pilgrim's fourth 10-year ISI Program Plan complies with these limitations and modifications. ISI, including pressure testing, of the SSW system in accordance with ASME Code Section XI (*Id. at* 1-35), and provides reasonable assurance of structural integrity and that significant degradation will be identified in a timely manner such that safety related systems will be able to perform their safety function.

A14b. (ATK) The ISI program plan referenced routine inspection, maintenance, and test requirements for the SSW system piping and heat exchanger inspections, along with the associated acceptance criteria for consistency with GL 89-13. These inspections are separate from, but supplement, the ASME Code Section XI Class 3 ISI inspections.

Regional inspectors use Inspection Procedure ("IP") 71111.07 to verify heat sink performance. (Staff Ex.15). As stated in Pilgrim Nuclear Power Station - NRC Integrated

Inspection Report 05000293/2006002 dated May 12, 2006, “The inspector reviewed performance tests, periodic cleaning, eddy current inspections, chemical control methods, tube leak monitoring, the extent of tube plugging, potential water hammer analysis, operating procedures, [and] maintenance practices.” (Staff Ex. 16 at 6). The inspector also confirmed that controls for selected components conformed to Entergy’s commitments to Generic Letter 89-13, “Service Water System Problems Affecting Safety Related Equipment.” The inspector did not identify any findings of significance. (*Id.*). The verifying of the heat sink performance provides assurance that the heat sink is capable of meeting its safety function.

Q15. How does Pilgrim’s Final Safety Analysis Report (“FSAR”) address the NRC regulations described above for the SSW system?

A15. (ATK) FSAR § 10.7 discusses the safety objective of the SSW system at Pilgrim. As discussed above, the SSW system provides a heat sink for the RBCCW system under transient and accident conditions. (1) The system is designed with sufficient redundancy so that no single active system component failure can prevent the system from achieving its safety objective. (2) The system is designed to continuously provide a supply of cooling water to the secondary side of the RBCCW heat exchangers adequate for the requirements of the RBCCW under transient and accident conditions. (Staff Ex. 17)

The SSW system consists of five vertical service water pumps located in the intake structure, and associated piping, valves, and instrumentation. The pumps discharge to a common header from which independent piping supplies each of the two cooling water loops.

Testing is performed on pumps and valves in accordance with the inservice testing program. The testing is performed per the ASME Code as required by 10 C.F.R. § 50.55a(f).

The buried portions of the 22-inch nominal diameter discharge piping from the last flange connections in the auxiliary building piping vault to the end of the discharge pipes at the seal well opening have been provided with a cured-in-place-pipe (“CIPP”) lining. The 240-feet total length loop “A” lining was installed in refueling outage (RFO-14) and the 225-feet total length “B” lining was installed in RFO-13. The CIPP liner material consists of a tube composed of nonwoven polyester felt material that is saturated with either an isophthalic polyester resin and catalyst system (Loop “A”) or epoxy resin and hardener system (Loop “B”) with a polyurethane or polyethylene inner membrane surface. The liner has a nominal ½” installed thickness. The resulting configuration is a rigid resin composite pipe within the original pipe with no requirements for bonding between the pipes. (Staff Ex. 17 at 10.7-2a)

Q16. Will the tests and inspections described above continue to be performed during the period of extended operation?

A16. Yes. The tests and inspections discussed above are performed as part of routine maintenance and operation. Those required under the regulations and TSs, will carry forward unless changed by an amendment to the regulations or to the operating license. Those tests and inspections covered by the FSAR can be changed by the Applicant, but only as permitted under 10 C.F.R. § 50.59. Changes to the ISI and IST are governed by 10 C.F.R. § 50.55a.

Q17. How does the NRC treat unexpected leakage from systems such as the SSW and CS?

A17. (TLC) Unexpected leakage from the pressure boundary of a system, such as the piping itself, welds, and valve bodies, is considered as operational leakage, and is a current licensing basis issue. Industry experience has shown that operational leakage from typical service water systems as a result of corrosion due to the nature of service water environments does occur. Because such leakage is a clear nonconformance to the expected condition of the system, treatment of operational leakage was provided in GL 91-18, “Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability.” (Staff Ex.18). This guidance was revised in NRC Regulatory Issue Summary (“RIS”) 2005-20, “Revision to Guidance Formerly Contained in NRC Generic Letter 91-18,’Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability,” dated

September 26, 2005. (Staff Ex.19). Specific guidance regarding operational leakage is provided in Appendix C, Article C.12, “Operational Leakage from Code Class 1, 2, and 3 Components,” to NRC Inspection Manual Part 9900, attachment to the RIS. (*Id.* at C-9). Article C.12 provides guidance for evaluating the structural integrity of the leaking component to perform its safety function and identifies actions which may be taken to determine the operability of the component. (*Id.* at C-10). This guidance makes no distinction as to whether the component or piping is buried or exposed.

Q18. What is the Staff’s conclusion regarding whether the inspections being performed under Pilgrim’s current license for routine maintenance and operation of buried pipes and tanks that could potentially contain radioactive liquid are adequate to detect leaks prior to challenging the buried piping’s ability to fulfill its safety function?

A18. (TLC) (ATK) The buried piping at Pilgrim that could potentially contain radioactive liquid is effectively managed by the inspections, testing, quality assurance, and corrective action programs performed under the current license. These programs provide reasonable assurance that significant leaks would be detected in a timely manner that will allow for action to be taken prior to the system being unable to perform its intended safety function.

Q19. Have you had an opportunity to review the testimony of Entergy’s witnesses regarding the testing, inspections and surveillances performed on the SSW, CS, and other systems?

A19. (TLC) (ATK) We have each reviewed Entergy’s testimony dated January 8, 2008.

Q20. Do you have an opinion regarding whether these tests and inspections are adequate to detect leaks before they would affect the ability of buried pipes to perform their intended safety function?

A20. (TLC) (ATK) Yes. The tests and inspections are discussed in the testimony of the Applicant’s expert witnesses and include: water level indicators in the CS system tanks that are checked every four hours (Entergy’s Testimony at 48), quarterly waterflow rate testing of the

HPCI and RCIC pumps and related corrective actions (*Id.* at 48-49), quarterly IST of flow rate to the HPCI and RCIC systems in accordance with the ASME code and Pilgrim TSs (*Id.* at 51), flowrate tests once after every outage and once every two years (*Id.*), and monthly flowrate test of the SSW system (*Id.* at 53). In our opinion, they provide reasonable assurance that during routine operation, leaks in the buried pipes in the CS and SSW systems will be detected before affecting the ability of the buried pipes to perform their intended function.

Q21. Does this conclude your testimony?

A21. Yes.

<u>Terence L. Chan, PE</u>
Statement of Professional Qualifications

<u>CURRENT POSTION:</u>

Branch Chief,	Division of Component Integrity Office of Nuclear Reactor Regulation U.S. Nuclear Regulatory Commission, Rockville, MD

<u>EDUCATION:</u>

B. NE.	Georgia Institute of Technology, 1977, Nuclear Engineering
MS	Georgia Institute of Technology, 1981, Mechanical Engineering

<u>LICENSES:</u>

Professional Engineer (Mechanical Eng.), Washington, DC #7997 (since 1983)

<u>SUMMARY:</u>

Nearly 30 years of experience in nuclear, mechanical and materials engineering in the nuclear power industry. Significant experience in the following areas:

- Mechanical Engineering
- System Design
- Nondestructive Examination
- Inspection
- Licensing
- Allegations
- Quality Assurance
- Construction
- American Society of Mechanical Engineers (ASME) Code Committees

<u>EXPERIENCE:</u>
<u>U.S. Nuclear Regulatory Commission, 02/09/1981 – Present</u>

06/2001 to Present – Chief, Piping and NDE Branch, Division of Component Integrity, Office of Nuclear Reactor Regulation

- Manage the day to day technical and administrative responsibilities of a technical staff, dealing with materials degradation, welding, and inspection issues. Specific issues include reactor vessel head degradation, and cracking of dissimilar metal welds.
- Responsible for the inservice inspection requirements of piping systems and components, pressure boundary integrity issues and nondestructive examination methods and qualification requirements.
- NRC representative to ASME, Section XI
  - Task Group on Alternate NDE

- Task Group on Alloy 600
- Working Group on General Requirements
- Subgroup on Nondestructive Examination

05/2000 to 06/2001 – Senior Mechanical Engineer, Materials and Chemical Engineering Branch, Division of Engineering, Office of Nuclear Reactor Regulation

- Technical lead for ASME Code issues.
- Peer reviewer of technical safety evaluations

10/1999 to 05/2000 - Commissioner Assistant, Office of Chairman Richard A. Meserve
02/1996 to 10/1999 - Commissioner Assistant, Office of the Chairman/Office of Commissioner Greta Joy Dicus

- Reviewed and advised on technical and policy matters related to reactor issues including License Renewal, Advanced Reactors, Risk-informed Regulations, Y2K, International Exports and Technology Transfer, Budget, NRC Organization Structure, Regulatory Reform, Decommissioning, and Deregulation.

08/1990 to 02/1996 - Section Chief, Mechanical Engineering Branch, Division of Engineering, Office of Nuclear Reactor Regulation

- Manage the day to day technical and administrative responsibilities of a technical staff, dealing with inservice surveillance and testing requirements of safety-related pumps and valves.
- Responsible for piping design requirements, seismic design requirements, and effects of thermal stratification in piping systems.

04/1986 to 08/1990 - Senior Project Manager/Project Manager, Division of Reactor Projects III, IV, and V, Office of Nuclear Reactor Regulation

- Project Manager for Trojan Nuclear Plant and Surry Power Station; Senior Project Manager for Palo Verde Nuclear Generating Station. Responsible for all licensing activities related to the facilities; coordination of issues between NRC, licensee, and other State and Federal agencies; and coordination of all technical reviews.
- Lead Project Manager for generic technical issues - pipe wall thinning, thermal stratification, and reactor vessel support embrittlement.

11/1983 to 04/1986 - Reactor Construction Engineer, Reactor Construction Programs Branch, Division of Quality Assurance, Safeguards and Inspection Programs, Office of Inspection and Enforcement

- Performed Construction Appraisal Team inspections at Clinton, Seabrook, Waterford, Shearon Harris, and Millstone 3. Lead inspector responsible for all mechanical engineering related systems and components (i.e., fluid piping systems, HVAC).

02/1981 to 11/1983 - Auxiliary Systems Engineer, Auxiliary Systems Branch, Division of Systems Technology, Office of Nuclear Reactor Regulation

- Performed licensing reviews of nuclear power plant applications. Reviewed Final Safety Analysis Reports. Determined the acceptability of the design of safety-related and "balance-of-plant" systems (e.g., spent fuel pool and cooling system, fuel storage, safe shutdown in the event of fire, emergency feedwater system, HVAC, ultimate heat sink, component cooling systems).

U. S. Tennessee Valley Authority; Bellefonte Nuclear Plant - Construction Engineer (06/1978 to 02/1981)

- Construction engineer responsible for the installation and preoperational testing of safety piping systems, supports and components.

Andrea T. Keim
Statement of Professional Qualifications

CURRENT POSITION:

Materials Engineer — Division of Component Integrity, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission (NRC), Rockville, MD

EDUCATION:
Bachelor's of Engineering - Stevens Institute of Technology, Materials and Metallurgical Engineering 1990
Master's of Science - Stevens Institute of Technology, Materials Science and Engineering 1995

SUMMARY:

Over 15 years of experience in materials engineering with over 12 years of experience in the nuclear power industry. Significant experience in the following areas:

- Materials Engineering
- Corrosion and Control
- Welding and Special Repair Processes
- License Renewal
- Nondestructive testing
- Review of Next Generation Power Plant Designs
- Quality Assurance
- American Society of Mechanical Engineers (ASME) Code Committees

EXPERIENCE:
U.S. Nuclear Regulatory Commission, July 1995 - Present

September 1997 to Present – Materials Engineer, Division of Component Integrity, Office of Nuclear Reactor Regulation

- Member of the Liquid Radioactive Release Lessons Learned Task Force, providing technical expertise on regulatory requirements for systems, structures and components related to radioactive leaks

- ASME Committee member for the working group on implementation of risk-based examinations

- Performed technical reviews related to plant relief requests

- Performed technical reviews related to license amendments including license renewal reviews

July 1995 – September 1997– Reactor Engineer Intern, Office of Nuclear Reactor Regulations

- Completed extensive formal training in nuclear reactor technology t

- Performed a series of developmental assignments throughout the agency to gain a broad perspective of its role.

NOVON Products, a Division of Warner Lambert, Applications Testing Engineer, 1990–1993 1990:

- Responsible for Technical Marketing for the biodegradable polymer productions providing technical data and reports to domestic and international customers.

- Interacted between sales representatives, customers, managers and research staff to develop products and test procedures to identify appropriate materials.

Consolidated Edison, Summer Intern – Summer 1989

- Failure analysis

- Evaluation of nondestructive testing equipment

Stevens Institute of Technology, Teaching Assistant, 1990-1991

- Responsible for research, development and teaching powder metallurgy laboratory class for sophomore level students.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

PREFILED TESTIMONY OF TERENCE L. CHAN

I, Terence L. Chan, do declare under penalty of perjury that my statements in the foregoing testimony and my attached statement of professional qualifications are true and correct to the best of my knowledge and belief.

/Original Signed By/
____
Terence L. Chan

Executed at Rockville, Maryland
This 29th day of January, 2008.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

PREFILED TESTIMONY OF ANDREA T. KEIM

I, Andrea T. Keim, do declare under penalty of perjury that my statements in the foregoing testimony and my attached statement of professional qualifications are true and correct to the best of my knowledge and belief.

/***Original Signed By/***
____
Andrea T. Keim

Executed at Rockville, Maryland
This 29th day of January, 2008.

January 29, 2008

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

NRC STAFF EXHIBIT LIST

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NUREG-1801, Rev. 1 (Sept. 2005) EXCERPT - XI.M34 “BURIED PIPING AND TANKS INSPECTION”	1
NUREG-1801, Rev. 1 (Sept. 2005) EXCERPT - XI.M20 “OPEN-CYCLE COOLING WATER SYSTEM”	2
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PILGRIM LICENSE RENEWAL APPLICATION EXCERPT - B.1.2 “BURIED PIPING AND TANKS INSPECTION”	4
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NRC STAFF

EXHIBIT 1

XI.M34 BURIED PIPING AND TANKS INSPECTION

Program Description

The program includes (a) preventive measures to mitigate corrosion, and (b) periodic inspection to manage the effects of corrosion on the pressure-retaining capacity of buried steel piping and tanks. Gray cast iron, which is included under the definition of steel, is also subject to a loss of material due to selective leaching, which is an aging effect managed under Chapter XI.M33, "Selective Leaching of Materials."

Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried piping and tanks are inspected when they are excavated during maintenance and when a pipe is dug up and inspected for any reason.

This program is an acceptable option to manage buried piping and tanks, except further evaluation is required for the program element/attributes of detection of aging effects (regarding inspection frequency) and operating experience.

Evaluation and Technical Basis

1. ***Scope of Program:*** 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 and tanks. Loss of material in these components, which may be exposed to aggressive soil environment, is caused by general, pitting, and crevice corrosion, and microbiologically-influenced corrosion (MIC). Periodic inspections are performed when the components are excavated for maintenance or for any other reason. The scope of the program covers buried components that are within the scope of license renewal for the plant.

2. ***Preventive Actions:*** In accordance with industry practice, underground piping and tanks are coated during installation with a protective coating system, such as coal tar enamel with a fiberglass wrap and a kraft paper outer wrap, a polyolifin tape coating, or a fusion bonded epoxy coating to protect the piping from contacting the aggressive soil environment.

3. ***Parameters Monitored/Inspected:*** The program monitors parameters such as coating and wrapping integrity that are directly related to corrosion damage of the external surface of buried steel piping and tanks. Coatings and wrappings are inspected by visual techniques. 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.

4. ***Detection of Aging Effects:*** Inspections performed to confirm that coating and wrapping are intact are an effective method to ensure that corrosion of external surfaces has not occurred and the intended function is maintained. Buried piping and tanks are opportunistically inspected whenever they are excavated during maintenance. When opportunistic, the inspections are performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems, within the areas made accessible to support the maintenance activity.

The applicant's program is to be evaluated for the extended period of operation. It is anticipated that one or more opportunistic inspections may occur within a ten-year period. Prior to entering the period of extended operation, the applicant is to verify that there is at least one opportunistic or focused inspection is performed within the past ten years. Upon entering the period of extended operation, the applicant is to perform a focused inspection within ten years, unless an opportunistic inspection occurred within this ten-year period. Any credited inspection should be performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems.

5. ***Monitoring and Trending:*** Results of previous inspections are used to identify susceptible locations.

6. ***Acceptance Criteria:*** Any coating and wrapping degradations are reported and evaluated according to site corrective actions procedures.

7. ***Corrective Actions:*** The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

8. ***Confirmation Process:*** See Item 7, above.

9. ***Administrative Controls:*** See Item 7, above.

10. ***Operating Experience:*** Operating experience shows that the program described here is effective in managing corrosion of external surfaces of buried steel piping and tanks. However, because the inspection frequency is plant-specific and depends on the plant operating experience, the applicant's plant-specific operating experience is further evaluated for the extended period of operation.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC STAFF

EXHIBIT 2

XI.M20 OPEN-CYCLE COOLING WATER SYSTEM

Program Description

The program relies on implementation of the recommendations of the Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-13 to ensure that the effects of aging on the open-cycle cooling water (OCCW) (or service water) system will be managed for the extended period of operation. The program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the OCCW system or structures and components serviced by the OCCW system.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program addresses the aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms. Because the characteristics of the service water system may be specific to each facility, the OCCW system is defined as a system or systems that transfer heat from safety-related systems, structures, and components (SSC) to the ultimate heat sink (UHS). If an intermediate system is used between the safety-related SSCs and the system rejecting heat to the UHS, that intermediate system performs the function of a service water system and is thus included in the scope of recommendations of NRC GL 89-13. The guidelines of NRC GL 89-13 include (a) surveillance and control of biofouling; (b) a test program to verify heat transfer capabilities; (c) routine inspection and a maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of safety-related systems serviced by OCCW; (d) a system walk down inspection to ensure compliance with the licensing basis; and (e) a review of maintenance, operating, and training practices and procedures.

2. ***Preventive Actions:*** The system components are constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from being exposed to aggressive cooling water environments. Implementation of NRC GL 89-13 includes a condition and performance monitoring program; control or preventive measures, such as chemical treatment, whenever the potential for biological fouling species exists; or flushing of infrequently used systems. Treatment with chemicals mitigates microbiologically-influenced corrosion (MIC) and buildup of macroscopic biological fouling species, such as blue mussels, oysters, or clams. Periodic flushing of the system removes accumulations of biofouling agents, corrosion products, and silt.

3. ***Parameters Monitored/Inspected:*** Adverse effects on system or component performance are caused by accumulations of biofouling agents, corrosion products, and silt. Cleanliness and material integrity of piping, components, heat exchangers, elastomers, and their internal linings or coatings (when applicable) that are part of the OCCW system or that are cooled by the OCCW system are periodically inspected, monitored, or tested to ensure heat transfer capabilities. The program ensures (a) removal of accumulations of biofouling agents, corrosion products, and silt, and (b) detection of defective protective coatings and corroded OCCW system piping and components that could adversely affect performance of their intended safety functions.

4. ***Detection of Aging Effects:*** Inspections for biofouling, damaged coatings, and degraded material condition are conducted. Visual inspections are typically performed; however, nondestructive testing, such as ultrasonic testing, eddy current testing, and heat transfer

capability testing, are effective methods to measure surface condition and the extent of wall thinning associated with the service water system piping and components, when determined necessary.

5. ***Monitoring and Trending:*** Inspection scope, method (e.g., visual or nondestructive examination [NDE]), and testing frequencies are in accordance with the utility commitments under NRC GL 89-13. Testing and inspections are done annually and during refueling outages. Inspections or nondestructive testing will determine the extent of biofouling, the condition of the surface coating, the magnitude of localized pitting, and the amount of MIC, if applicable. Heat transfer testing results are documented in plant test procedures and are trended and reviewed by the appropriate group.

6. ***Acceptance Criteria:*** Biofouling is removed or reduced as part of the surveillance and control process. The program for managing biofouling and aggressive cooling water environments for OCCW systems is preventive. Acceptance criteria are based on effective cleaning of biological fouling organisms and maintenance of protective coatings or linings are emphasized.

7. ***Corrective Actions:*** Evaluations are performed for test or inspection results that do not satisfy established acceptance criteria and a problem or condition report is initiated to document the concern in accordance with plant administrative procedures. The corrective actions program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined, and an action plan is developed to preclude repetition. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. ***Confirmation Process:*** Site 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. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Significant microbiologically-influenced corrosion (NRC Information Notice [IN] 85-30), failure of protective coatings (NRC IN 85-24), and fouling (NRC IN 81-21, IN 86-96) have been observed in a number of heat exchangers. The guidance of NRC GL 89-13 has been implemented for approximately 10 years and has been effective in managing aging effects due to biofouling, corrosion, erosion, protective coating failures, and silting in structures and components serviced by OCCW systems.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, July 18, 1989.

NRC STAFF

EXHIBIT 3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

July 18, 1989

TO: ALL HOLDERS OF OPERATING LICENSES OR CONSTRUCTION PERMITS FOR NUCLEAR POWER PLANTS

SUBJECT: SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT (GENERIC LETTER 89-13)

Purpose:

Nuclear power plant facilities of licensees and applicants must meet the minimum requirements of the General Design Criteria (GDC) in 10 CFR Part 50, Appendix A. In particular, "GDC 44--Cooling Water" requires provision of a system (here called the service water system) "to transfer heat from structures, systems, and components important to safety to an ultimate heat sink" (UHS). "GDC 45--Inspection of Cooling Water System" requires the system design "to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system." "GDC 46--Testing of Cooling Water System" requires the design "to permit appropriate periodic pressure and functional testing."

In addition, nuclear power plant facilities of licensees and applicants must meet the minimum requirements for quality assurance in 10 CFR Part 50, Appendix B. In particular, Section XI, "Test Control," requires that "a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents."

Recent operating experience and studies have led the NRC to question the compliance of the service water systems in the nuclear power plants of licensees and applicants with these GDC and quality assurance requirements. Therefore, this Generic Letter is being issued to require licensees and applicants to supply information about their respective service water systems to assure the NRC of such compliance and to confirm that the safety functions of their respective service water systems are being met.

Background:

Bulletin No. 81-03: The NRC staff has been studying the problems associated with service water cooling systems for a number of years. At Arkansas Nuclear One, Unit 2, on September 3, 1980, the licensee shut down the plant when the NRC Resident Inspector discovered that the service water flow rate through the

CONTACT: C. Vernon Hodge, NRR
492-1169

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containment cooling units did not meet the technical specification requirement. The licensee determined the cause to be extensive flow blockage by Asiatic clams (Corbicula species, a non-native fresh water bivalve mollusk). Prompted by this event and after determining that it represented a generic problem of safety significance, the NRC issued Bulletin No. 81-03, "Flow Blockage of Cooling Water to Safety System Components by Corbicula sp. (Asiatic Clam) and Mytilus sp. (Mussel)."

The bulletin required licensees and applicants to assess macroscopic biological fouling (biofouling) problems at their respective facilities in accordance with specific actions. A careful assessment of responses to the bulletin indicated that existing and potential fouling problems are generally unique to each facility ("Closeout of IE Bulletin 81-03...", NUREG/CR-3054), but that surprisingly, more than half the 129 nuclear generating units active at that time were considered to have a high potential for biofouling. At that time, the activities of licensees and applicants for biofouling detection and control ranged widely and, in many instances, were judged inappropriate to ensure safety system reliability. Too few of the facilities with high potential for biofouling had adopted effective control programs.

Information Notice No. 81-21: After issuance of Bulletin No. 81-03, one event at San Onofre Unit 1 and two events at the Brunswick station indicated that conditions not explicitly discussed in the bulletin can occur and cause loss of direct access to the UHS. These conditions include

1. Flow blockage by debris from shellfish other than Asiatic clams and blue mussels.

2. Flow blockage in heat exchangers causing high pressure drops that can deform baffles and allow flow to bypass heat exchanger tubes.

3. A change in operating conditions, such as a change from power operation to a lengthy outage, that permits a buildup of biofouling organisms.

The NRC issued Information Notice No. 81-21 to describe these events and concerns.

Generic Issue 51: By March 1982, several reports of serious fouling events caused by mud, silt, corrosion products, or aquatic bivalve organisms in open-cycle service water systems had been received. These events led to plant shutdowns, reduced power operation for repairs and modifications, and degraded modes of operation. This situation led the NRC to establish Generic Issue 51, "Improving the Reliability of Open-Cycle Service Water Systems." To resolve this issue, the NRC initiated a research program to compare alternative surveillance and control programs to minimize the effects of fouling on plant safety. Initially, the program was restricted to a study of biofouling, but in 1987 the program was expanded to also address fouling by mud, silt, and corrosion products.

This research program has recently been completed and the results have been published in "Technical Findings Document for Generic Issue 51...," NUREG/CR-5210. The NRC has concluded that the issue will be resolved when licensees and applicants implement either the recommended surveillance and control program described below (Enclosure 1) or its equivalent for the service water system at their respective facilities. Many licensees experiencing service water macroscopic biofouling problems at their plants have found that these techniques will effectively prevent recurrence of such problems. The examination of alternative corrective action programs is documented in "Value/Impact Analysis for Generic Issue 51...," NUREG/CR-5234.

Continuing Problems: Since the advent of Generic Issue 51, a considerable number of events with safety implications for the service water system have been reported. A number of these have been described in information notices, which are listed in "Information Notices Related to Fouling Problems in Service Water Systems" (Enclosure 3). Several events have been reported within the past 2 years: Oconee Licensee Event Report (LER) 50-269/87-04, Rancho Seco LER 50-312/87-36, Catawba LER 50-414/88-12, and Trojan LER 50-344/88-29. In the fall of 1988, the NRC conducted a special announced safety system functional inspection at the Surry station to assess the operational readiness of the service water and recirculation spray systems. A number of regulatory violations were identified (NRC Inspection Reports 50-280/88-32 and 50-281/88-32).

AEOD Case Study: In 1987, the Office for Analysis and Evaluation of Operational Data (AEOD) in the NRC initiated a systematic and comprehensive review and evaluation of service water system failures and degradations at light water reactors from 1980 to early 1987. The results of this AEOD case study are published in "Operating Experience Feedback Report - Service Water System Failures and Degradations," NUREG-1275, Volume 3 (Enclosure 4).

Of 980 operational events involving the service water system reported during this period, 276 were deemed to have potential generic safety significance. A majority (58 percent) of these events with generic significance involved system fouling. The fouling mechanisms included corrosion and erosion (27 percent), biofouling (10 percent), foreign material and debris intrusion (10 percent), sediment deposition (9 percent), and pipe coating failure and calcium carbonate deposition (1 percent).

The second most frequently observed cause of service water system degradations and failures is personnel and procedural errors (17 percent), followed by seismic deficiencies (10 percent), single failures and other design deficiencies (6 percent), flooding (4 percent), and significant equipment failures (4 percent).

During this period, 12 events involved a complete loss of service water system function. Several of the significant causes listed above for system degradation were also contributors to these 12 events involving system failure.

The study identified the following actions as potential NRC requirements.

1. Conduct, on a regular basis, performance testing of all heat exchangers, which are cooled by the service water system and which are needed to perform a safety function, to verify heat exchanger heat transfer capability.

2. Require licensees to verify that their service water systems are not vulnerable to a single failure of an active component.

3. Inspect, on a regular basis, important portions of the piping of the service water system for corrosion, erosion, and biofouling.

4. Reduce human errors in the operation, repair, and maintenance of the service water system.

Recommended Actions To Be Taken by Addressees:

On the basis of the discussion above, the NRC requests that licensees and applicants perform the following or equally effective actions to ensure that their service water systems are in compliance and will be maintained in compliance with 10 CFR Part 50, Appendix A, General Design Criteria 44, 45, and 46 and Appendix B, Section XI. If a licensee or applicant chooses a course of action different from the recommendations below, the licensee or applicant should document and retain in appropriate plant records a justification that the heat removal requirements of the service water system are satisfied by use of the alternative program.

Because the characteristics of the service water system may be unique to each facility, the service water system is defined as the system or systems that transfer heat from safety-related structures, systems, or components to the UHS. If an intermediate system is used between the safety-related items and the system rejecting heat to the UHS, it performs the function of a service water system and is thus included in the scope of this Generic Letter. A closed-cycle system is defined as a part of the service water system that is not subject to significant sources of contamination, one in which water chemistry is controlled, and one in which heat is not directly rejected to a heat sink. If all these conditions are not satisfied, the system is to be considered an open-cycle system in regard to the specific actions required below. (The scope of closed cooling water systems is discussed in the industrial standard "Operation and Maintenance of Nuclear Power Plants," ASME/ANSI OM-1987, Part 2.)

I. For open-cycle service water systems, implement and maintain an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling. A program acceptable to the NRC is described in "Recommended Program to Resolve Generic Issue 51" (Enclosure 1). It should be noted that Enclosure 1 is provided as guidance for an acceptable program. An equally effective program to preclude biofouling would also be acceptable. Initial activities should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter. All activities should be documented and all relevant documentation should be retained in appropriate plant records.

II. Conduct a test program to verify the heat transfer capability of all safety-related heat exchangers cooled by service water. The total test program should consist of an initial test program and a periodic retest program. Both the initial test program and the periodic retest program should include heat exchangers connected to or cooled by one or more open-cycle systems as defined above. Operating experience and studies indicate that closed-cycle service water systems, such as component cooling water systems, have the potential for significant fouling as a consequence of aging-related in-leakage and erosion or corrosion. The need for testing of closed-cycle system heat exchangers has not been considered necessary because of the assumed high quality of existing chemistry control programs. If the adequacy of these chemistry control programs cannot be confirmed over the total operating history of the plant or if during the conduct of the total testing program any unexplained downward trend in heat exchanger performance is identified that cannot be remedied by maintenance of an open-cycle system, it may be necessary to selectively extend the test program and the routine inspection and maintenance program addressed in Action III, below, to the attached closed-cycle systems.

A program acceptable to the NRC for heat exchanger testing is described in "Program for Testing Heat Transfer Capability" (Enclosure 2). It should be noted that Enclosure 2 is provided as guidance for an acceptable program. An equally effective program to ensure satisfaction of the heat removal requirements of the service water system would also be acceptable.

Testing should be done with necessary and sufficient instrumentation, though the instrumentation need not be permanently installed. The relevant temperatures should be verified to be within design limits. If similar or equivalent tests have not been performed during the past year, the initial tests should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter.

As a part of the initial test program, a licensee or applicant may decide to take corrective action before testing. Tests should be performed for the heat exchangers after the corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance. In the periodic retest program, a licensee or applicant should determine after three tests the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests. Therefore, in the periodic retest program, to assist that determination, tests should be performed for the heat exchangers before any corrective actions are taken. As in the initial test program, tests should be repeated after any corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance.

An example of an alternative action that would be acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing for degraded performance of the heat exchanger. This alternative might apply to small heat exchangers, such as lube oil coolers or pump bearing coolers or readily serviceable heat exchangers located in low radiation areas of the facility.

In implementing the continuing program for periodic retesting of safety-related heat exchangers cooled by service water in open-cycle systems, the initial frequency of testing should be at least once each fuel cycle, but after three tests, licensees and applicants should determine the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests and meet the requirements of GDC 44, 45, and 46. The minimum final testing frequency should be once every 5 years. A summary of the program should be documented, including the schedule for tests, and all relevant documentation should be retained in appropriate plant records.

III. Ensure by establishing a routine inspection and maintenance program for open-cycle service water system piping and components that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of the safety-related systems supplied by service water. The maintenance program should have at least the following purposes:

A. To remove excessive accumulations of biofouling agents, corrosion products, and silt;

B. To repair defective protective coatings and corroded service water system piping and components that could adversely affect performance of their intended safety functions.

This program should be established before plant startup following the first refueling outage beginning 9 months after the date of this letter. A description of the program and the results of these maintenance inspections should be documented. All relevant documentation should be retained in appropriate plant records.

IV. Confirm that the service water system will perform its intended function in accordance with the licensing basis for the plant. Reconstitution of the design basis of the system is not intended. This confirmation should include a review of the ability to perform required safety functions in the event of failure of a single active component. To ensure that the as-built system is in accordance with the appropriate licensing basis documentation, this confirmation should include recent (within the past 2 years) system walkdown inspections. This confirmation should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter. Results should be documented and retained in appropriate plant records.

V. Confirm that maintenance practices, operating and emergency procedures, and training that involves the service water system are adequate to ensure that safety-related equipment cooled by the service water system will function as intended and that operators of this equipment will perform effectively. This confirmation should include recent (within the past 2 years) reviews of practices, procedures, and training modules. The intent of this action is to reduce human errors in the operation, repair, and maintenance of the service water system. This confirmation should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter. Results should be documented and retained in appropriate plant records.

Reporting Requirements:

Pursuant to the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f), each licensee and applicant shall advise the NRC whether it has established programs to implement Recommendations I-V of this Generic Letter or that it has pursued an equally effective alternative course of action. Each addressee's response to this requirement for information shall be made to the NRC within 180 days of receipt of this Generic Letter. Licensees and applicants shall include schedules of plans for implementation of the various actions. The detailed documentation associated with this Generic Letter should be retained in appropriate plant records.

The response shall be submitted to the appropriate regional administrator under oath and affirmation under the provisions of Section 182a, Atomic Energy Act of 1954, as amended and 10 CFR 50.54(f). In addition, the original cover letter and a copy of any attachment shall be transmitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington DC 20555, for reproduction and distribution.

In addition to the 180-day response, each licensee and applicant shall confirm to the NRC that all the recommended actions or their justified alternatives have been implemented within 30 days of such implementation. This response need only be a single response to indicate that all initial tests or activities have been completed and that continuing programs have been established.

This request is covered by the Office of Management and Budget Clearance Number 3150-0011, which expires December 31, 1989. The estimated average burden is 1000 man-hours per addressee response, including assessing the actions to be taken, preparing the necessary plans, and preparing the 180-day response. This estimated average burden pertains only to these identified response-related matters and does not include the time for actual implementation of the recommended actions. Comments on the accuracy of this estimate and suggestions to reduce the burden may be directed to the Office of Management and Budget, Reports Management, Room 3208, New Executive Office Building, Washington, DC 20503 and to the U.S. Nuclear Regulatory Commission, Records and Reports Management Branch, Office of Information and Resources Management, Washington, DC 20555.

Although no specific request or requirement is intended, the following information would be helpful to the NRC in evaluating the cost of this Generic Letter:

1. Addressee time necessary to perform the requested confirmation and any needed follow-up actions.

2. Addressee time necessary to prepare the requested documentation.

If there are any questions regarding this letter, please contact the regional administrator of the appropriate NRC regional office or your project manager in this office.

Sincerely,

James G. Partlow
Associate Director for Projects
Office of Nuclear Reactor Regulation

Enclosures:
1. "Recommended Program to Resolve Generic Issue 51"
2. "Program for Testing Heat Transfer Capability"
3. "Information Notices Related to Fouling Problems in Service Water Systems"
4. "Operating Experience Feedback Report - Service Water System Failures and Degradations in Light Water Reactors," NUREG-1275, Volume 3
5. List of Most Recently Issued Generic Letters

Enclosure 1

RECOMMENDED PROGRAM
TO RESOLVE GENERIC ISSUE 51

This enclosure describes a program acceptable to the NRC for meeting the objectives of the requested Action I in the proposed generic letter. Both Action I and this enclosure are based upon the recommendations described in "Technical Findings Document for Generic Issue 51: Improving the Reliability of Open-Cycle Service-Water Systems," NUREG/CR-5210, August 1988, and "Value/Impact Analysis for Generic Issue 51: Improving the Reliability of Open-Cycle Service-Water Systems," NUREG/CR-5234, February 1989. The NRC has concluded that Generic Issue 51 will be resolved when licensees and applicants implement either the recommended surveillance and control program addressed in this enclosure or an equally effective alternative course of action to satisfy the heat removal requirements of the service water system.

Water Source Type	Surveillance Techniques	Control Techniques
Marine or Estuarine (brackish) or Freshwater with clams	A	B and C
Freshwater without clams	A and D	B and C

A. The intake structure should be visually inspected, once per refueling cycle, for macroscopic biological fouling organisms (for example, blue mussels at marine plants, American oysters at estuarine plants, and Asiatic clams at freshwater plants), sediment, and corrosion. Inspections should be performed either by scuba divers or by dewatering the intake structure or by other comparable methods. Any fouling accumulations should be removed.

B. The service water system should be continuously (for example, during spawning) chlorinated (or equally effectively treated with another biocide) whenever the potential for a macroscopic biological fouling species exists (for example, blue mussels at marine plants, American oysters at estuarine plants, and Asiatic clams at freshwater plants). Chlorination or equally effective treatment is included for freshwater plants without clams because it can help prevent microbiologically influenced corrosion. However, the chlorination (or equally effective) treatment need not be as stringent for plants where the potential for macroscopic biological fouling species does not exist compared to those plants where it does. Precautions should be taken to obey Federal, State, and local environmental regulations regarding the use of biocides.

C. Redundant and infrequently used cooling loops should be flushed and flow tested periodically at the maximum design flow to ensure that they are not fouled or clogged. Other components in the service water system should be tested on a regular schedule to ensure that they are not fouled or clogged. Service water cooling loops should be filled with chlorinated or equivalently treated water before layup. Systems that use raw service water as a source, such as some fire protection systems, should also be chlorinated or equally effectively treated before layup to help prevent microbiologically influenced corrosion. Precautions should be taken to obey Federal, State, and local environmental regulations regarding the use of biocides.

D. Samples of water and substrate should be collected annually to determine if Asiatic clams have populated the water source. Water and substrate sampling is only necessary at freshwater plants that have not previously detected the presence of Asiatic clams in their source water bodies. If Asiatic clams are detected, utilities may discontinue this sampling activity if desired, and the chlorination (or equally effective) treatment program should be modified to be in agreement with paragraph B, above.

Enclosure 2

PROGRAM FOR TESTING HEAT TRANSFER CAPABILITY

This enclosure describes a program acceptable to the NRC for meeting the objectives of the requested Action II in the proposed generic letter. Both Action II and this enclosure are based in part on "Operating Experience Feedback Report - Service Water System Failures and Degradations," NUREG-1275, Volume 3, November 1988 and "Technical Findings Document for Generic Issue 51: Improving the Reliability of Open Cycle Service Water Systems," NUREG/CR-5210, August 1988. This enclosure reflects continuing operational problems, inspection reports, and industry standards ("Operation and Maintenance of Nuclear Power Plants," ASME/ANSI OM-1987, Part 2.) The NRC requests licensees and applicants to implement either the steps addressed in this enclosure or an equally effective alternative course of action to satisfy the heat removal requirements of the service water system.

Both the initial test program and the periodic retest program should include all safety-related heat exchangers connected to or cooled by one or more open-cycle service water systems. A closed-cycle system is defined as a part of the service water system that is not subject to significant sources of contamination, one in which water chemistry is controlled, and one in which heat is not directly rejected to a heat sink. (The scope of closed cooling water systems is discussed in the industrial standard, "Operation and Maintenance of Nuclear Power Plants," ASME/ANSI OM-1987, Part 2.) If during the conduct of the total testing program any unexplained downward trend in heat exchanger performance is identified that cannot be remedied by maintenance of an open-cycle system, it may be necessary to selectively extend the test program to the attached closed-cycle system.

Testing should be done with necessary and sufficient instrumentation, though the instrumentation need not be permanently installed.

As a part of the initial test program, a licensee or applicant may decide to take corrective action before testing. Tests should be performed for the heat exchangers after the corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance. In the periodic retest program, a licensee or applicant should determine after three tests the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests. Therefore, in the periodic retest program, to assist that determination, tests should be performed for the heat exchangers before any corrective actions are taken. As in the initial test program, tests should be repeated after any corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance.

An example of an alternative action that would be acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing for degraded performance of the heat exchanger. This alternative might apply to small heat exchangers, such as lube oil coolers or pump bearing coolers or readily serviceable heat exchangers located in low radiation areas of the facility.

In implementing the continuing program for periodic retesting of safety-related heat exchangers cooled by service water in open-cycle systems, the initial frequency of testing should be at least once each fuel cycle, but after three tests, licensees and applicants should determine the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests and meet the requirements of GDC 44, 45, and 46. The minimum final testing frequency should be once every 5 years.

I. For all heat exchangers

Monitor and record cooling water flow and inlet and outlet temperatures for all affected heat exchangers during the modes of operation in which cooling water is flowing through the heat exchanger. For each measurement, verify that the cooling water temperatures and flows are within design limits for the conditions of the measurement. The test results from periodic testing should be trended to ensure that flow blockage or excessive fouling accumulation does not exist.

II. In addition to the considerations for all heat exchangers in Item I, for water-to-water heat exchangers

A. Perform functional testing with the heat exchanger operating, if practical, at its design heat removal rate to verify its capabilities. Temperature and flow compensation should be made in the calculations to adjust the results to the design conditions. Trend the results, as explained above, to monitor degradation. An example of this type of heat exchanger would be that used to cool a diesel generator. Engine jacket water flow and temperature and service water flow and temperature could be monitored and trended during the diesel generator surveillance testing.

B. If it is not practical to test the heat exchanger at the design heat removal rate, then trend test results for the heat exchanger efficiency or the overall heat transfer coefficient. Verify that heat removal would be adequate for the system operating with the most limiting combination of flow and temperature.

III. In addition to the considerations for all heat exchangers in Item I, for air-to-water heat exchangers

A. Perform efficiency testing (for example, in conjunction with surveillance testing) with the heat exchanger operating under the maximum heat load that can be obtained practically. Test results should be corrected for the off-design conditions. Design heat removal capacity should be verified. Results should be trended, as explained above, to identify any degraded equipment.

B. If it is not possible to test the heat exchanger to provide statistically significant results (for example, if error in the measurement exceeds the value of the parameter being measured), then

1. Trend test results for both the air and water flow rates in the heat exchanger.

2. Perform visual inspections, where possible, of both the air and water sides of the heat exchanger to ensure cleanliness of the heat exchanger.

IV. In addition to the considerations for all heat exchangers in Item I, for types of heat exchangers other than water-to-water or air-to-water heat exchangers (for example, penetration coolers, oil coolers, and motor coolers)

A. If plant conditions allow testing at design heat removal conditions, verify that the heat exchanger performs its intended functions. Trend the test results, as explained above, to monitor degradation.

B. If testing at design conditions is not possible, then provide for extrapolation of test data to design conditions. The heat exchanger efficiency or the overall heat transfer coefficient of the heat exchanger should be determined whenever possible. Where possible, provide for periodic visual inspection of the heat exchanger. Visual inspection of a heat exchanger that is an integral part of a larger component can be performed during the regularly scheduled disassembly of the larger component. For example, a motor cooler can be visually inspected when the motor disassembly and inspection are scheduled.

NRC STAFF

EXHIBIT 4

B.1.2 BURIED PIPING AND TANKS INSPECTION

Program Description

The Buried Piping and Tanks Inspection Program at PNPS is comparable to the program described in NUREG-1801, Section XI.M34, Buried Piping and Tanks Inspection.

This 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.

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.

NUREG-1801 Consistency

The Buried Piping and Tanks Inspection Program at PNPS will be consistent with program attributes described in NUREG-1801, Section XI.M34, Buried Piping and Tanks Inspection, with one exception.

Exceptions to NUREG-1801

The Buried Piping and Tanks Inspection Program at PNPS will be consistent with program attributes described in NUREG-1801, Section XI.M34, Buried Piping and Tanks Inspection, with the following exception.

Attributes Affected	Exception
4. Detection of Aging Effects	Inspections via methods that allow assessment of pipe condition without excavation may be substituted for inspections requiring excavation solely for the purpose of inspection.[1]

Exception Note

1. Methods such as phased array UT technology provide indication of wall thickness for buried piping without excavation. Use of such methods to identify the effects of aging is preferable to excavation for visual inspection, which could result in damage to coating or wrappings.

Enhancements

None

Operating Experience

The Buried Piping and Tanks Inspection Program at PNPS is a new program for which there is no operating experience.

Conclusion

Implementation of the Buried Piping and Tanks Inspection Program will provide reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

NRC STAFF

EXHIBIT 5

B.1.28 SERVICE WATER INTEGRITY

Program Description

The Service Water Integrity Program at PNPS is comparable to the program described in NUREG-1801, Section XI.M20, Open-Cycle Cooling Water System.

This program relies on implementation of the recommendations of GL 89-13 to ensure that the effects of aging on the salt service water (SSW) system are managed for the period of extended operation. The program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the SSW system or structures and components serviced by the SSW system.

NUREG-1801 Consistency

The Service Water Integrity Program at PNPS is consistent with the program described in NUREG-1801, Section XI.M20, Open-Cycle Cooling Water System with exceptions.

Exceptions to NUREG-1801

The Service Water Integrity Program at PNPS is consistent with the program described in NUREG-1801, Section XI.M20, Open-Cycle Cooling Water System with the following exceptions.

Attributes Affected	Exceptions
2. Preventive Actions	NUREG-1801 states that system components are lined or coated. Components are lined or coated only where necessary to protect the underlying metal surfaces.[1]
5. Monitoring and Trending	NUREG-1801 states that testing and inspections are performed annually and during refueling outages. The PNPS program requires tests and inspections each refueling outage.[2]

Exception Notes

1. NUREG-1801 states that system components are constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from being exposed to aggressive cooling water environments. Not all PNPS system components are lined or coated. Components are lined or coated only where necessary to protect the underlying metal surfaces.

2. NUREG-1801 program entails testing and inspections performed annually and during refueling outages. The PNPS program requires tests and inspections each refueling outage, but not annually. Since aging effects are typically manifested over several years, the difference in inspection and testing frequency is insignificant.

Enhancements

None

Operating Experience

Results of heat transfer capability testing of the reactor building closed cooling water (RBCCW) heat exchangers from 2001 through 2004 show that the heat exchangers are capable of removing the required amount of heat. Confirmation of adequate thermal performance provides evidence that the program is effective for managing fouling of SSW cooled heat exchangers.

Results of SSW visual inspections, eddy current testing, ultrasonic testing, and radiography testing from 1998 through 2004 revealed areas of erosion and areas of corrosion on internal and external surfaces. SSW butterfly valves, pump discharge check valves, air removal valves, and pipe spools have been replaced with components made of corrosion resistant materials. Also, RBCCW heat exchanger channel assemblies have been replaced and tubes have been sleeved to address erosion and corrosion. Identification of degradation and corrective action prior to loss of intended function provide evidence that the program is effective for managing loss of material for SSW system components.

Visual inspections of SSW piping revealed degradation of the lining in original SSW carbon steel rubber lined piping. Pipe lining is intended to protect pipe internal surfaces from erosion and corrosion. Therefore, SSW piping has been replaced with carbon steel pipe with cured-in-place rubber lining, relined with a ceramic epoxy compound, or replaced with titanium pipe. Identification of degradation and corrective action prior to loss of intended function provide evidence that the program is effective for managing loss of material for SSW system components.

Conclusion

The Service Water Integrity Program has been effective at managing aging effects. The Service Water Integrity Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended function consistent with the current licensing basis for the period of extended operation.

NRC STAFF

EXHIBIT 6

confirmed that their implementation prior to the period of extended operation would make the existing AMP consistent with the GALL AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement A.2.1.28 for this AMP and concludes that it provides (pending incorporation of the applicant's commitments) an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.16 Service Water Integrity Program

Summary of Technical Information in the Application. LRA Section B.1.28, "Service Water Integrity," describes the existing Service Water Integrity Program as consistent, with exceptions, with GALL AMP XI.M20, "Open-Cycle Cooling Water System."

This program relies on implementation of the recommendations of GL 89-13 to manage the effects of aging on the SSW system for the period of extended operation. The program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the SSW system or structures and components it services.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report and documented a detailed audit evaluation of this AMP in Audit and Review Report Section 3.0.3.2.16. The staff reviewed the exceptions to determine whether the AMP remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Service Water Integrity Program for which the applicant claims consistency with GALL AMP XI.M20 and found them consistent. Furthermore, the staff concludes that the applicant's Service Water Integrity Program reasonably assures management of aging effects so components crediting this program can perform intended functions consistent with the CLB during the period of extended operation. The staff finds the applicant's Service Water Integrity Program acceptable as consistent with the recommended GALL AMP XI.M20, "Service Water Integrity," with exceptions as described:

Exception 1. The LRA states an exception to the GALL Report program element "preventive actions," specifically:

> NUREG-1801 states that system components are lined or coated. Components are lined or coated only where necessary to protect the underlying metal surfaces.

The LRA states that the GALL Report states that system components are constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from exposure to aggressive cooling water environments. Not all system components are lined or coated, only where necessary to protect the underlying metal surfaces.

During the audit and review, the staff asked the applicant for applications in which components are not coated or lined and the materials of construction.

The applicant responded that the SSW supply piping is constructed of titanium, a material which has shown excellent corrosion resistance in this environment. The other components in the SSW supply are small-bore piping for vents and drains, pump and valve bodies, and heat exchanger tubes. All of these components are constructed of copper alloys with demonstrated good corrosion resistance in this environment and operating experience shows that the Service Water Integrity Program manages loss of material and takes corrective action before loss of component intended functions.

On this basis, the staff finds the exception acceptable.

Exception 2. The LRA states an exception to the GALL Report program element "monitoring and trending," specifically:

> NUREG-1801 states that testing and inspections are performed annually and during RFOs. The PNPS program requires tests and inspections during each RFO.

The LRA states that the GALL Report program entails testing and inspections annually and during RFOs. The applicant's program requires tests and inspections during each RFO but not annually. As aging effects typically are manifested over several years, the difference in inspection and testing frequency is insignificant.

During the audit and review, the staff evaluated the applicant's inspection interval and agreed that adverse conditions caused by the aging effects in the service water systems manifest over several years. Operating experience shows that a two-year interval has not led to adverse service water system operating conditions; therefore, the difference between a one-year and two-year inspection and testing frequency is insignificant.

On this basis, the staff finds the exception acceptable.

In addition, the applicant stated that it will enhance this program to clarify the procedures for trending heat transfer test results (Commitment No. 24). The staff finds this acceptable.

Operating Experience. LRA Section B.1.28 states that results of heat transfer capability testing of the reactor building closed cooling water (RBCCW) heat exchangers from 2001 through 2004 show that the heat exchangers can remove the required amount of heat. Confirmation of adequate heat removal provides evidence that the program effectively manages fouling of SSW-cooled heat exchangers.

Results of SSW visual inspections, eddy current testing, UT, and radiography testing from 1998 through 2004 revealed areas of erosion and corrosion on internal and external surfaces. SSW butterfly valves, pump discharge check valves, air removal valves, and pipe spools have been replaced with components made of corrosion-resistant materials, RBCCW heat exchanger channel assemblies have been replaced, and tubes have been sleeved to address erosion and corrosion. Revelation of degradation and corrective action prior to loss of intended function provide evidence that the program effectively manages loss of material for SSW system components.

Visual inspections of SSW piping revealed degradation of the lining in original SSW carbon steel rubber-lined piping intended to protect pipe internal surfaces from erosion and corrosion. Therefore, SSW piping has been replaced with carbon steel pipe with rubber lining cured in place, relined with a ceramic epoxy compound, or replaced with titanium pipe. Revelation of degradation and corrective action prior to loss of intended function provide evidence that the program effectively manages loss of material for SSW system components.

The staff reviewed the operating experience presented in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

The staff confirmed that the "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Section A.2.1.30, the applicant provided the UFSAR supplement for the Service Water Integrity Program. The staff reviewed this section and determined that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Service Water Integrity Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.17 Structures Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.29.2, "Structures Monitoring," describes the existing Structures Monitoring Program as consistent, with enhancements, with GALL AMP XI.S6, "Structures Monitoring Program."

Structures monitoring in accordance with 10 CFR 50.65 (Maintenance Rule) is addressed in Regulatory Guide 1.160 and Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants 93-01. These two documents guide development of licensee-specific programs to monitor the condition of structures and structural components within the scope of the Maintenance Rule so there is no loss of structure or structural component intended function. As protective coatings are not relied upon to manage aging effects for structures in the Structures Monitoring Program, the program does not address protective coating monitoring and maintenance.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report and documented a detailed audit evaluation of this AMP in Audit and Review Report Section 3.0.3.2.17. The staff reviewed the enhancements to determine whether the AMP remained adequate to manage the aging effects for which it is credited.

NRC STAFF

EXHIBIT 7

PDC No: 99-21 "Q" ☒ Non-"Q" ☐

PDC/FRN Title: Excavation for SSW Pipe Replacement (RFO #12 scope) Major ☐ Minor ☒

NARRATIVE (Rev. 2)

A. DESCRIPTION OF CHANGE

- Problem Statement: Salt Service Water (SSW) A Loop pipe spools JF 29-11-4 and 5, and B Loop pipe spools JF 29-13-5 and 6, are degraded and may require replacement. These sections of pipe are located in the yard area just to the south of the circulating water intake and seal well structures, and will require a shored excavation approximately 10 ft. wide by 90 ft. long by 12 ft. deep (400 cu.yd. of material).

- Objectives/Criteria/Modification Scope: The objective of this modification is to delineate the work necessary to safely accomplish the excavation for the pipe replacement scope, and to restore the work area to an acceptable condition. This work scope may also expand to include temporary or other permanent modifications to deal with unforeseen conditions in the excavation. Replacement of the A and B Loop SSW piping, if required will be addressed under a separate modification package. Replacement of the paved surface and any requirements for supplemental fill to restore the subgrade will be performed as a Maintenance activity under a separate package.

Design work is being performed in phases to support an expedited schedule for implementation. Phase I is being released at this time. If additional phases or other changes are required, they will be released using the the FRN process.

Phase I - This scope covers the design of the excavation bounded by Piles 1E through 9E, and 1W through 9W, to access to A Loop pipe spool JF 29-11-5, and B Loop pipe spool JF 29-13-6. This scope was previously released for implementation under the Exhibit 5B process (NOP83E1). This Phase I scope is incorporated now as part of this PDC.

- Safety Classification and Boundary Limits: The Salt Service Water System is Safety Related. Excavation for possible pipe replacement activities will take place when the plant is in a cold condition, and decay heat removal is being performed independently by a third SSW return line installed under Temporary Modification 99-35. Consequently, both the A and B Loop SSW return lines will be out-of-service and replacement work can be performed at the same time.

  The following clarifications are provided to delineate safety related impacts:

  In-situ material and backfill (i.e. structural fill or flowable fill) placed under the SSW pipe, and backfill placed around and above the SSW pipe for a distance of 2 feet over the top, provides support and protection for design conditions, and is considered Class I.

  Retaining structures supporting soils not affecting safety related components perform no safety function with respect to the SSW pipe during this modification, and are considered Class II, Non Safety-Related.

  Backfill outside Class I limits is considered Class II, Non Safety-Related.

  The SSW pipe is considered operable from a civil/structural perspective when protected by backfill having a thickness of 4 feet over the top of the pipe

- Maintenance Rule Impact: None

ISSUED FOR CONSTRUCTION

B. PROCUREMENT OF MATERIALS/COMPONENTS

Excavated soils will be reused to bed the replacement pipe and for backfill. Flowable fill may also be used in selected locations, procured by CGI for Class I applications, and per the GEI Specification for Class II applications. Materials specified for construction of the excavation and associated support structures may be procured Non-Q. It is anticipated that most of these materials will be furnished by the contractor

C. CONTROLLED DOCUMENTS/TRAINING AFFECTED

• PNPS Procedures	None
• Vendor Manuals	None
• Technical Specifications:	None
• Priority A Design Documents:	None
• Priority B Design Documents:	Drawing C20
• FSAR Sections:	None
• Operator Training:	None
• Technical Training.	None

D. DOCUMENTS GOVERNING DESIGN AND INSTALLATION

BECo Drawing C20-4-REP
GEI Drawing ES-1
GEI Geotechnical Specification for SSW Piping Replacement

E SAFETY IMPACT DURING IMPLEMENTATION

As discussed previously, SSW pipe replacement activities will take place when the plant is in a cold condition, and decay heat removal is being performed independently by a third SSW return line installed under Temporary Modification 99-35. Consequently, both the A and B Loop SSW return lines will be out-of-service, and not required to be performing, or available to perform, safety functions during this time. As a result, safety impacts during implementation are limited to the protection of other safety related components which could be affected by construction activities. This would include for example, the Appendix R Manhole 28A and associated duct banks immediately adjacent to the proposed excavation limit, and any other items having safety related functions which are within, or in close proximity of, the excavation as determined by Engineering.

ISSUED FOR CONSTRUCTION

F. DESIGN ADEQUACY

Excavation for possible replacement of degraded SSW pipe will be accomplished within a soldier pile/timber sheathing structure, engineered to resist lateral soil pressure. During drilling and excavation activities, both the A and B Loop SSW return lines will be out-of-service, and not required to be performing, or available to perform, safety functions. Other safety related components which could be affected by construction activities are protected by structures designed to Class II over Class I criteria.

Dig safe measures have included extensive drawing searches to identify buried components. Ground detection radar has been employed to augment this effort. Holes for auger drilling will be located by survey and individually approved prior to drilling. These measures cannot guarantee all buried components have been identified and precisely located, hence there is some potential that unidentified items could be damaged during drilling and excavation activities. Nevertheless, reasonable assurance is provided that safety related components, and components essential to power generation, will not be affected.

Excavated materials will be controlled in accordance with radiological procedures. Materials will be stockpiled in a manner consistent with Security considerations. Excavated soil materials will be replaced in accordance with specifications for controlled structural backfill.

Geotechnical specifications, drawings and testing services are furnished by a qualified supplier under this modification package. Supporting analysis and calculations are received and accepted under the SUDDS/RF process.

G. INSPECTION/HOLD POINTS/POSTWORK TESTING AND ACCEPTANCE CRITERIA

Backfilling around and over replacement SSW pipe shall not be permitted to proceed until completion of necessary pipe installation inspections as may be required by the associated modification package.

Testing of materials for Class I bedding and backfill under, around and above replacement SSW pipe shall be performed in accordance with the GEI Specification and BECo Commercial Grade Item (CGI) document, as applicable:

- Flowable fill (aka controlled density fill) used for backfill shall be inspected in accordance with the requirements of the applicable CGI. If a conflict exists between the GEI Specification and the BECo CGI, the latter shall have precedence. The pipe shall be properly anchored to prevent flotation. CGI dedication for flowable fill used for Class I applications shall be verified by Quality Control personnel.
- Soil backfill shall re-use excavated materials, and in the sequence specified in the "Plan for Radiological Controls" (Narrative Paragraph J.). The bedding material providing support to the invert of the pipe shall compacted to the requirements of the GEI Specification for Zone A material to the extent necessary based on disturbance of the subgrade. All other soil backfill around and above the pipe shall be compacted to the requirements of the GEI Specification for Zone B material. Compaction testing for soils used for Class I applications shall be verified by Quality Control personnel.

Soil retaining structures designed to support the excavation walls and considered Class II, Management Q, shall be inspected to ensure requirements of the drawings and specifications are followed. In-process surveillance inspection on a sample basis shall be performed. No special testing is required

Inspection of Class II, Non Safety-Related work is not required

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H COMPONENT NUMBERING CHANGE - na

I ALARA DESIGN REVIEW: N/A This work is being performed outside the RCA

J. INPUT FOR MAINTENANCE WORK PLAN

Excavation Plan

- General

The excavation contractor shall develop a proposed plan for BECo approval, for the location and configuration of stockpiles of excavated materials. Material stockpiles shall be located and controlled in a manner which precludes the possibility of damaging components associated with Temporary Modification 99-35, or other components in the yard area. Lines of sight required by Security shall be preserved to the maximum extent possible. The plan shall include provisions to identify the locations of existing paving joints associated with previous repairs. This data likely indicates buried utilities which, if not already shown on BECo excavation drawings, may require test pits to permit identification.

Holes to be augered for soldier piles shall be located by a survey. Each hole location shall be approved by Engineering prior to being drilled. Test pits shall be dug by hand when directed by the Engineering as necessary to locate potential drilling obstructions. Excavated materials shall be controlled in accordance with the radiological requirements. Soils shall be re-used during the backfilling/restoration phase to the maximum extent possible. As determined by Engineering, no large rocks shall be permitted to be placed in contact with underground equipment during backfilling activities. The maximum size of gravel in the backfill within one foot of the pipe should be no larger than about 2".

- Plan for Radiological Controls

Radiological considerations will require excavated materials to be segregated and controlled in a prescribed fashion. This plan for control may be modified in-process at the direction of the RPM or designated representative. The following definitions are applied to layers of materials to be excavated:

Material	Description
Layer A	Bituminous asphalt paving materials
Layer B	The 6" soil layer immediately beneath Layer A
Layer C	The 6" soil layer immediately beneath Layer B
Layer D	All other soils beneath Layer C

Layer A paving materials shall be stockpiled in a segregated area for pre-release radiological survey prior to disposal off site. The method of excavation would preferably result in intact pieces of paving, minimizing the amounts of loose aggregate which is more expensive to process for disposal.

Layer B, C and D soil materials shall be stockpiled in different locations during the excavation process. These materials shall be properly identified and controlled to prevent from being mixed together. The backfilling sequence shall be as follows: Layer D soil materials shall be replaced first, followed by Layer C, followed by Layer B.

Backfill

Steel piles shall be cut off approximately 2 ft. below finish grade and abandoned-in-place. Pressure treated timber sheathing may be abandoned-in-place, timber sheathing not pressure treated shall be removed prior to backfilling. Replacement of excavated soils shall be accomplished in accordance with the following sequence: Layer D soil materials shall be replaced first, up to its previous elevation, followed by Layer C, followed by Layer B.

CAUTION: For various reasons, it is expected there will be extra Layer D material remaining after it has been restored to pre-excavation elevations. This is acceptable and desirable since there must be a sufficient volume to replace all Layer C and B materials in their original locations in the excavation.

Backfill shall be compacted as required by the specification. Where conditions may preclude accomplishment of compaction requirements by normal methods using machinery, Engineering may approve alternatives to accomplish an equivalent result.

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required by 10 CFR 54.21(d).

3.0.3.1.13 Water Chemistry Control - BWR Program

Summary of Technical Information in the Application. LRA Section B.1.32.2, "Water Chemistry Control - BWR," describes the existing Water Chemistry Control-BWR Program as consistent with GALL AMP XI.M2, "Water Chemistry."

To manage aging effects caused by corrosion and cracking mechanisms the program relies on monitoring and control of water chemistry based on EPRI Report 1008192 (Boiling Water Reactor Vessel and Internals Project (BWRVIP)-130). BWRVIP-130 has three sets of guidelines: for primary water; for condensate and feedwater; and for control rod drive (CRD) mechanism cooling water. EPRI guidelines in BWRVIP-130 also include recommendations for controlling water chemistry in the torus, condensate storage tanks, demineralized water storage tanks, and spent fuel pool. The Water Chemistry Control - BWR Program optimizes the primary water chemistry to minimize potential loss of material and cracking by limiting causative contaminant levels in the reactor coolant system. Additionally, the applicant has instituted hydrogen water chemistry to limit the potential for intergranular stress corrosion cracking (IGSCC) through the reduction of dissolved oxygen in the treated water.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report and documented a detailed evaluation of this AMP in Audit and Review Report Section 3.0.3.1.13.

GALL AMP XI.M2 recommends that for "susceptible locations" a one-time inspection program verification program may be appropriate. The staff asked the applicant whether it intended to implement a one-time inspection program for this water chemistry control program and, if so, why this intent is not included in the UFSAR supplement, Appendix A.

In response, the applicant stated that the One-Time Inspection Program described in LRA Section B.1.23 includes inspections to verify the effectiveness of the water chemistry control AMPs by confirming that unacceptable cracking, loss of material, and fouling has not occurred. The discussions in LRA Section 3, Table 1 link the One-Time Inspection Program and water chemistry control programs for susceptible components; however, for clarity, in its response dated July 19, 2006, the applicant stated that the effectiveness of the Water Chemistry Control – Auxiliary Systems, BWR, and Closed Cooling Water Programs is confirmed by the One-Time Inspection Program.

With the change to Appendix A the staff finds the applicant's response acceptable.

The staff finds the applicant's Water Chemistry – BWR Program acceptable as consistent with the recommended GALL AMP XI.M2, "Water Chemistry."

Operating Experience. LRA Section B.1.32.2 states that from 1998 through 2004 after several condition reports of adverse trends in parameters monitored by the Water Chemistry Control - BWR Program the applicant acted within the corrective action program to preclude unacceptable parameter values. Continuous confirmation of water quality and corrective actions taken before adverse trends reach control limits provide evidence that the program effectively manages component aging effects. From 1998 through 2004, after several condition reports of parameters monitored by the Water Chemistry Control - BWR Program were outside administrative limits but still within EPRI acceptance criteria and the applicant acted within the corrective action program to preclude violations of EPRI acceptance criteria. Continuous confirmation of water quality and corrective action before parameters reach control limits provide evidence that the program effectively manages component aging effects.

From 1998 through 2004, there were two incidents in which parameters monitored by the Water Chemistry Control-BWR Program were outside of EPRI acceptance criteria:

(1) Following a power outage on March 29, 2002, dissolved oxygen measurement from the B high-pressure feedwater (HPFW) train was ~28 ppb below the minimum required reading of 30 ppb (EPRI action level 1). Dissolved oxygen measured from the A HPFW train and condensate demineralizer effluent (CDE) were acceptable (~ 70 to 80 ppb). The root cause was B HPFW sample line contamination, not actually low oxygen in the feedwater. The B HPFW sample line was replaced.

(2) On October 28, 2002, HPFW and CDE dissolved oxygen levels spiked to 400 to 500 ppb for about 15 minutes before returning to normal. EPRI action level 1 for HPFW dissolved oxygen is 200 ppb. The root cause was inadequate filling of the D demineralizer prior to its return to service. The procedure states, "It is EXTREMELY important that all air is vented from a Cond Demin before it is placed in service to prevent air injection into the Feedwater System." Procedural steps were emphasized for proper venting to mitigate elevated oxygen levels in the feedwater system.

The applicant further stated that continuous confirmation of water quality and timely corrective action provide evidence that the program effectively manages component aging effects. QA audits in 2000 and 2002 revealed no issues or findings with impact on program effectiveness. A QA audit in 2004 revealed that reactor coolant sodium and lithium analyses had not been weekly during the first half of 2004. The applicant took corrective action to replace the analysis instrument and to complete the analyses as required. A corporate assessment in 2003 found areas for improvement in administrative controls but no issues or findings with impact on program effectiveness.

The staff also reviewed the operating experience presented in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

The staff confirmed that the "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Section A.2.1.37, the applicant provided the UFSAR supplement for the Water Chemistry Control - BWR Program. The staff reviewed this section and determined that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Water Chemistry Control - BWR Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 AMPs That Are Consistent with the GALL Report with Exceptions and/or Enhancements

In LRA Appendix B, the applicant stated that the following AMPs are, or will be, consistent with the GALL Report with exceptions or enhancements:

- Buried Piping and Tanks Inspection Program
- BWR CRD Return Line Nozzle Program
- BWR Feedwater Nozzle Program
- BWR Penetrations Program
- BWR Stress Corrosion Cracking Program
- BWR Vessel ID Attachment Welds Program
- BWR Vessels Internals Program
- Diesel Fuel Monitoring Program
- Fatigue Monitoring Program
- Fire Protection Program
- Fire Water System Program
- Metal-Enclosed Bus Inspection Program
- Oil Analysis Program
- Reactor Head Closure Studs Program
- Reactor Vessel Surveillance Program
- Service Water Integrity Program
- Structures Monitoring Program
- Water Control Structures Monitoring Program
- Water Chemistry Control - Closed Cooling Water Program

For AMPs that the applicant claimed are consistent with the GALL Report, with exception(s) and/or enhancement(s), the staff performed an audit and review to confirm that those attributes or features of the program for which the applicant claimed consistency were indeed consistent. The staff also reviewed the exception(s) and/or enhancement(s) to the GALL Report to determine whether they were acceptable and adequate. The results of the staff's audits and reviews are documented in the following sections.

3.0.3.2.1 Buried Piping and Tanks Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.2, "Buried Piping and Tanks Inspection," describes the new Buried Piping and Tanks Inspection Program as consistent, with exception, with GALL AMP XI.M34, "Buried Piping and Tanks Inspection."

This 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

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Based on its review, the staff finds the response acceptable because the applicant will review plant-specific operating experience against the industry experience described in the GALL Report. With additional operating experience lessons learned, the applicant can adjust the program elements.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Non-EQ Insulated Cables and Connections Program will adequately manage the aging effects for which this AMP is credited.

The staff confirmed that the "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Section A.2.1.23, the applicant provided the UFSAR supplement for the Non-EQ Insulated Cables and Connections Program. In a letter dated September 13, 2006, the applicant stated that it will implement the Non-EQ Insulated Cables and Connections Program as described in LRA Section B.1.21 before the period of extended operation (Commitment No. 17).

The staff reviewed this section and determined that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Non-EQ Insulated Cables and Connections Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.8 One-Time Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.23, "One-Time Inspection," describes the new One-Time Inspection Program as consistent with GALL AMPs XI.M32, "One-Time Inspection," and XI.M35, "One-Time Inspection of ASME Code Class I Small-Bore Piping."

The One-Time Inspection Program will be implemented prior to the period of extended operation. The one-time inspection activity for small-bore piping in the reactor coolant system and systems that form the reactor coolant pressure boundary will be comparable to GALL AMP XI.M35 and verify the effectiveness of the AMP to confirm the absence of aging effects.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report and documented a detailed evaluation of this AMP in Audit and Review Report Section 3.0.3.1.8.

During the audit and review, the staff asked the applicant how the sample of piping welds four inches and smaller will be selected for nondestructive examination.

The applicant responded that the One-Time Inspection Program will inspect small-bore piping in the reactor coolant system and systems that form the reactor coolant pressure boundary. This inspection will include a statistically significant sample of welds of each material and environment combination in Class 1 piping equal to or less than 4-inch nominal pipe size (NPS). The initial population will include all Class 1 small-bore piping, and actual locations will be selected for physical location, exposure levels, nondestructive examination (NDE) techniques, and locations specified in NRC Information Notice (IN) 97-46, "Un-Isolable Crack in High-Pressure Injection Piping." The staff further asked the applicant to clarify whether it uses volumetric examinations to detect cracking in butt welds.

In its response, the applicant revised the program evaluation report to state:

> Combinations of non-destructive examinations (including VT-1, enhanced VT-1, ultrasonic, and surface techniques) will be performed by qualified personnel following procedures that are consistent with Section XI of ASME Code and 10CFR50, Appendix B. Volumetric examinations are used to detect cracking in butt welds. Actual inspection locations will be based on physical accessibility, exposure levels, NDE techniques and locations identified in NRC IN 97-46, "Un-isolable Crack in High-Pressure Injection piping."

Based on the above, the staff found the response acceptable.

During the audit and review, the staff asked the applicant how it will handle the aging of small piping socket welds.

The applicant responded that during the fourth inservice inspection (ISI) interval it plans both VT-2 and penetrant testing (PT) examinations, at a minimum, of socket welds in accordance with the fourth interval ISI program plan. The one-time inspection of small-bore piping does not exclude locations based on geometry. Therefore, Class 1 small-bore piping socket welds will be selected for one-time inspection based on physical location and exposure levels.
In a letter dated September 13, 2006, the applicant stated that the One-Time Inspection Program will also include destructive or nondestructive examination of one socket-welded connection using techniques proven by past industry experience to be effective for the identification of cracking in small-bore socket welds. Should an inspection opportunity not occur (e.g., socket weld failure or socket weld replacement), a susceptible small-bore socket weld will be examined either destructively or nondestructively prior to entering the period of extended operation. Since small-bore piping socket-weld connection will be either destructively or nondestructively examined at least once, the staff found the applicant's response acceptable.

Upon further discussions the staff concluded that the destructive or nondestructive examination of one or more socket welds would not contribute significant additional information on the condition of socket welds. Socket welds fail by vibrational fatigue with cracks initiating from their inside surfaces. The time required for fatigue crack initiation is very long compared to the time to propagate through a wall. Therefore, a surface examination or destructive examination of a socket weld is unlikely to detect problems. In addition, there is no history of significant socket weld failures. The staff presented this information to the Advisory Committee on Reactor Safeguards (ACRS) Subcommittee on the Oyster Creek License Renewal on January 18, 2007, and it accepted the staff conclusions on socket welds.

In a letter dated February 23, 2007, the applicant amended Commitment No. 20 to remove references to socket welds.

The staff reviewed those portions of the applicant's One-Time Inspection Program for which the applicant claimed consistency with GALL AMP XI.M32 and GALL AMP XI.M35 and found that they are consistent with these GALL AMPs. On the basis of its review, the staff concludes that the applicant's One-Time Inspection Program provided assurance that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly as not to affect the intended function of the component or structure. The staff finds the applicant's One-Time Inspection Program acceptable because it conforms to the recommended GALL AMP XI.M32, "One-Time Inspection" and GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping."

Operating Experience. LRA Section B.1.23 states that there is no operating experience for the new One-Time Inspection Program. Industry and plant-specific operating experience will be considered appropriately in the development of this program.

As this program is new, the staff reviewed the License Renewal Project Operating Experience Review Report in general for small-pipe issues. This report provides information from condition reports and program owner interviews and covers the last five years. The staff determined that the applicant has a good corrective action program that promptly detects age-related degradation.

The staff confirmed that the "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Section A.2.1.25, the applicant provided the UFSAR supplement for the One-Time Inspection Program. During the audit and review, the staff noted that the applicant's description of the One-Time Inspection Program in the UFSAR supplement in LRA Appendix A did not include, as a commitment, implementation of the new program Nor did it indicate that this program is new. The applicant was asked to justify why LRA Appendix A did not include a commitment for the new program.

In its response dated September 13, 2006, the applicant included Commitment No. 20 for implementation of this new program. Commitment No. 20 also includes the one-time destructive or nondestructive examination of small-bore socket weld connections.

As a result of the staff's presentation to the ACRS on January 18, 2007, the applicant has since amended Commitment No. 20 to remove references to socket welds.

The staff reviewed this section and determined that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's One-Time Inspection Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the

UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.9 Selective Leaching Program

Summary of Technical Information in the Application. LRA Section B.1.27, "Selective Leaching," describes the new Selective Leaching Program as consistent with GALL AMP XI.M33, "Selective Leaching of Materials."

The Selective Leaching Program will ensure the integrity of components made of cast iron, bronze, brass, and other alloys exposed to raw water, treated water, or groundwater that may cause selective leaching. The program will include a one-time visual inspection and hardness measurement of selected components that may be susceptible to determine whether loss of material due to selective leaching has occurred and whether the loss will affect component ability to perform intended functions for the period of extended operation. The program will start prior to the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report and documented a detailed evaluation of this AMP in Audit and Review Report Section 3.0.3.1.9.

Based on its review, the staff finds the Selective Leaching Program consistent with GALL AMP XI.M33, "Selective Leaching of Materials," including the operating experience attribute.

Operating Experience. LRA Section B.1.27 states that there is no operating experience for the new Selective Leaching Program.

During the audit and review, the staff requested operating experience with circulating water pump replacement due to selective leaching. The applicant responded that it had replaced P-105A ("A" circulating sea water pump) in RFO 15 (April 2005) when the vendor (Flowserve) informed it that a cast iron circulating water pump failure had occurred at the New Boston Fossil Station in 2004 due to graphitization. That pump was of a design similar to that of the PNPS pump with six additional years of submerged operation in salt water. Six core samples of the pump casing were sent out to a materials laboratory for analysis, and the results confirmed graphitization. The applicant plans to replace P-105B in RFO 17 based on the core sample analysis from P-105A columns. The applicant also has purchased columns for P-105B overhaul/replacement onsite. The new pump columns are cast iron enhanced with the addition of 3 to 5 percent nickel to improve strength and graphitization resistance. The original columns were ASTM A48 CL 35 with 1.75- to 2.25-percent nickel.

The staff confirmed that the "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Section A.2.1.29, the applicant provided the UFSAR supplement for the Selective Leaching Program. The description in LRA Appendix A did not indicate that this program is new nor did it include a commitment to implement it. The applicant was asked why LRA Appendix A did not include a commitment for the new program.

NRC STAFF

EXHIBIT 10

Entergy

Entergy Nuclear Operations, Inc.
Pilgrim Station
600 Rocky Hill Road
Plymouth, MA 02360

William J. Riggs
Director, Nuclear Assessment

December 6, 2002

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

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

Pilgrim Nuclear Power Station Fourth Ten-Year Inserveice Testing (IST) Program and Request for Approval of IST Relief Requests

LETTER NUMBER: 2.02.109

Dear Sir or Madam:

Entergy Nuclear Operations, Inc. (Entergy) has revised the Pilgrim Nuclear Power Station (PNPS) Inservice Testing (IST) Program as required by 10CFR50.55a(f)(4)(ii) for the fourth 10-year interval starting December 7, 2002.

This submittal dockets Pilgrim IST program, Procedure No. 8.I.1.1. and requests NRC approval of IST relief requests, as described in this letter.

The revised IST Program complies with 1995 Edition through 1996 Addenda of the OM Code for Operation and Maintenance of Nuclear Power Plants, Section IST requirements with a few exceptions. These exceptions invoke 10CFR50.55a(f)(4)(iv), the use of portions of later approved ASME OM Code editions and 10CFR50.55a(f)(5)(iii) the notification that conformance with certain code requirements are impractical.

The NRC has recently approved 1998 Edition through 2000 Addenda of the OM Code for Operation and Maintenance of Nuclear Power Plants, (OMb Code - 2000). The following portions of the OMb Code - 2000 will be adopted into the revised IST Program (There are no other related requirements within the OMb Code – 2000 for these paragraphs):

- Appendix I-1390, Test Frequency, Class 2 and Class 3 Pressure Relief Devices that are Used for Thermal Relief Application.
- Appendix I-4110(h) and Appendix I-4130(g), Pressure Relief Devices - a minimum of 5-minute time elapse between successive openings.
- Deletion ISTA 2.1, Inspection – Duties of Inspector, Inspector Qualifications, and Access for Inspector.

A summary table of the IST Program Relief Requests requested for approval is enclosed (Attachment 1). This summary table provides a brief description of the impracticality or hardship requiring relief. The updated program Valve Relief Request No. 1 (VR-01) and No. 2 (VR-02) were recently reviewed and granted for ten years in a NRC Safety Evaluation Report (SER) dated September 17, 2002 and May 2, 2001, respectively.

A047

The details of the relief requests are specified in the IST Program Section 7.0 (Attachment 2) as pump and valve relief requests. A relief is requested where PNPS determined a non-conformance to certain Code requirement(s). The relief request provides either an alternative of acceptable level of quality and safety, an alternative since a hardship exists without a compensating increase in the level of quality and safety, or an alternative because it is an impractical requirement for the facility to meet.

PNPS has developed the following schedule plan for implementation of the updated program surveillance requirements:

Subsection ISTB, Inservice Testing of Pumps, will be implemented three months from December 7, 2002, with the exception of Reactor Building Closed Cooling Water (RBCCW) and High Pressure Coolant Injection (HPCI) pump testing, which will be implemented upon receipt of NRC approval of the pump relief requests. Until then Pilgrim will continue to comply with the third 10-year IST Interval program requirements for RBCCW and HPCI pumps.

Implementation of Subsection ISTC, Inservice Testing of Valves, will begin three months from December 7, 2002.

Entergy requests timely NRC review and approval of IST Relief Requests in order to support implementation of the new program.

If you have any questions or require additional information, please contact Mr. Bryan Ford, Licensing Manager, at (508) 830-8403.

Sincerely,

W.J. Riggs

Attachments: 1. Relief Request Summary Table – 1 page
2. Procedure No. 8.I.1.1, "Inservice Pump and Valve Testing Program" – 178 pages

cc: Mr. Travis Tate, Project Manager
Office of Nuclear Reactor Regulation
Mail Stop: 0-8B-1
U.S. Nuclear Regulatory Commission
1 White Flint North
11555 Rockville Pike
Rockville, MD 20852

U.S. Nuclear Regulatory Commission
Region 1
475 Allendale Road
King of Prussia, PA 19406

Senior Resident Inspector

202109

ATTACHMENT 2

PROCEDURE NO. 8.I.1.1,

INSERVICE PUMP AND VALVE TESTING PROGRAM

1.0 PURPOSE AND SCOPE

This Procedure encompasses and controls the PNPS Inservice Testing (IST) Program. It identifies the scope of components (pumps and valves) and testing requirements for compliance with 10CFR50.55a(f), Inservice Testing Requirements. This Procedure will be utilized for the IST Program submittal to satisfy ISTA 2.2.3 Inservice Test Interval and to identify impractical Code requirements in accordance with 10CFR50.55a(f)(5).

Impractical Code requirements are reviewed and dispositioned by the Nuclear Regulatory Commission (NRC) and documented in a Safety Evaluation Report authored by the Office of Nuclear Reactor Regulation as related to the Inservice Testing Program and Requests for Relief The NRC will grant program relief requests pursuant to 10CFR50.55a(a)(3)(i), 10CFR50 55a(a)(3)(ii), or 10CFR50.55a(f)(6)(i). Granting of relief ensures that the IST Program has satisfactorily demonstrated that either: 1) the proposed alternative provides an acceptable level of quality and safety, 2) compliance would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety, or 3) conformance with certain requirements of the applicable Code edition and addenda is impractical for its facility.

2.0 DISCUSSION

The scope of the IST Program includes those safety-related pumps and valves which are part of the Reactor coolant pressure boundary and must meet the requirements applicable to components classified as ASME Code Class 1. Additionally, other safety-related pumps and valves that perform a function to shut down the Reactor or maintain the Reactor in a safe shutdown condition, mitigate the consequences of an accident, or provide overpressure protection for safety-related systems meet the test requirements applicable to components which are classified as ASME Code Class 2 or Class 3. This scope is limited to those pumps and valves identified as meeting ASME Code Class 1, 2, or 3 in accordance with Regulatory Guide 1.26 classifications. The pumps and valves not performing a function as stated above or those meeting the exclusion requirements of the OMa Code need not be tested, but the bases for a component's exclusion must be justified. TDBD-121, "Topical Design Basis Document for In-Service Testing (IST)", provides the bases information related to IST Program exclusions.

Non-ASME Code Class safety-related pumps and valves that perform a function to shut down the Reactor or maintain the Reactor in a safe shutdown condition, mitigate the consequences of an accident, or provide overpressure protection for safety-related systems are to be tested under the requirements of 10CFR50 Appendix B. The scope of the PNPS Appendix B Test Program includes those safety-related pumps and valves identified as non-ASME Code Class in accordance with Regulatory Guide 1.26 but would be considered ASME Code Class 1, 2, 3.

This Procedure details the following items: compliance requirements, general information, pump hydraulic circuits, and tables of the components (pumps and valves) tested. The last Section (7.0) contains Valve Justifications (i.e., cold shutdown, Refuel Outage, Disassembly Examination, and Series Valve Pairs) and Relief Requests. In addition, the Procedure references the Condition Monitoring Program for check valves.

The Procedure's pump and valve tables provide a cross-reference between a component test requirement and a Station Procedure implementing the test. Additional information is provided within this component listing: safety class, category, test frequency, test parameters, Relief Requests, justifications, and remarks. Newly incorporated component/test requirements will have implementing Procedures identified for future incorporation. All newly identified component/test requirements shall be initially tested during the next scheduled frequency (i.e., quarterly, cold shutdown, refueling interval, and 2 years) following Procedure approval date. These newly incorporated component/test requirements will be identified by an asterisk (*) next to the implementing Procedure. When using (*) Procedures for postmaintenance testing, the current approved Procedure should be reviewed for applicability (i e , is the new test requirement or component incorporated)

PNPS 8.I.1, *"Administration of Inservice Pump and Valve Testing"*, covers the administrative requirements for the development, performance, and maintenance of the PNPS Inservice Test Program in accordance with the ASME OMa Code for Operation and Maintenance of Nuclear Power Plants, and includes the 1995 Edition through 1996 Addenda.

Station ALARA practices have been considered when addressing ASME Code test requirements within this Procedure. When test requirements are added or revised, good ALARA practices should be incorporated to minimize personnel dose.

3.0 REFERENCES

[1] 10CFR50 Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants

[2] 10CFR50 Appendix J, Primary Reactor Containment Leakage Testing

[3] 10CFR50.55a(b), Code and Standards, Reference Applicability

[4] 10CFR50.55a(f), Inservice Testing Requirements

[5] ASME Code, Mandatory Appendix I, Inservice Testing of Pressure Relief Device in Light-Water Reactor Power Plants

[6] ASME Code, Subsection ISTA, General Requirements

5.2.4 Core Spray (CS) Pumps

[1] Test Group B - pumps that are not operated routinely except for testing.

[2] Test Frequency/Method

CS pumps are tested quarterly using the Group B Test Method and biennially using the Comprehensive Test Method.

[3] Hydraulic Test Path

Each pump shall be tested by establishing a flow path with suction from and discharge returning to the Torus. Using the CS Full Flow Test Valve for throttling, establish a flow rate in accordance with current Technical Specifications requirements. Pump discharge and suction pressures shall be recorded and the differential pressure will be calculated and compared to the established value.

[4] Instrumentation

(a) <u>Inlet Pressure</u> (psig) M&TE test gauges at PI-40A, PI-40B.

(b) <u>Discharge Pressure</u> (psig) M&TE test gauges at PT-1460A, PT-1460B.

(c) <u>Flow rate</u>, Q (GPM) Flow indicators FI-1450-4A (Loop A) and FI-1450-4B (Loop B) or EPIC Computer Points CSP002 (Loop A) and CSP004 (Loop B).

5 2.5 High Pressure Coolant Injection (HPCI) Pump

[1] Test Group B - a pump that is not operated routinely except for testing

[2] Test Frequency/Method

The HPCI pump (reference PR-02) is tested quarterly using the Group B Test Method and biennially using the Comprehensive Test Method when adequate steam pressure is available.

[3] Hydraulic Test Path

The HPCI pump (main/booster integral unit) shall be tested by establishing a flow path with suction from and discharge returning to the CST. Using the HPCI Full Flow Test Valve for throttling, establish the speed and flow rate in accordance with current Technical Specifications requirements. Pump discharge and suction pressure shall be recorded. The differential pressure will be calculated and compared to the established value

[4] Instrumentation

(a) Inlet Pressure (psig): PI-2340-1 or M&TE test gauge at PI-2381 (Quarterly Group B Test). M&TE test gauge at PI-2381 (Biennial Comprehensive Test).

(b) Discharge Pressure (psig). M&TE test gauge at PI-2357

(c) Flow rate, Q (GPM). FI-2340-1.

(d) Speed, N (RPM): M&TE tachometer.

5.2.6 Reactor Core Isolation Cooling (RCIC) Pump

[1] Test Group B - a pump that is not operated routinely except for testing.

[2] Test Frequency/Method

The RCIC pump is tested quarterly using the Group B Test Method and biennially using the Comprehensive Test Method when adequate steam pressure is available.

[3] Hydraulic Test Path

The RCIC pump shall be tested by establishing a flow path from and returning to the CST. Using the full flow test valve for throttling, establish the speed and flow rate in accordance with current Technical Specifications requirements Pump discharge and suction pressures shall be recorded. The differential pressure will be calculated and compared to the established value

[4] Instrumentation

(a) Inlet Pressure (psig): PI-1340-2 or M&TE gauge at 1360-20 (Quarterly Group B Test). M&TE test gauge at 1360-20 (Biennial Comprehensive Test).

(b) Discharge Pressure (psig): M&TE test gauge at PI-1360-5

(c) Flow rate, Q (GPM): FI-1340-1.

(d) Speed, N (RPM): M&TE tachometer.

NRC STAFF

EXHIBIT 11

LIMITING CONDITIONS FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

C. HPCI System

1. The HPCI system shall be operable whenever there is irradiated fuel in the reactor vessel, reactor pressure is greater than 150 psig., and reactor coolant temperature is greater than 365°F, except as specified in 3.5.C.2 below.

2. From and after the date that the HPCI system is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 14 days unless such system is sooner made operable, providing that during such 14 days all active components of the ADS system, the RCIC system, the LPCI system and both core spray systems are operable.

3. If the requirements of 3.5.C cannot be met, an orderly shutdown of the reactor shall be initiated and the reactor shall be in the Cold Shutdown Condition within 24 hours.

SURVEILLANCE REQUIREMENTS

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

C. HPCI System

1. HPCI system testing shall be as follows:

a.	Simulated Automatic Actuation Test	Once/ Operating Cycle
b.	Pump Operability	When tested as specified in 3.13, verify that the HPCI pump delivers at least 4250 GPM for a system head corresponding to a reactor pressure of 1000 psig.
c.	Motor Operated Valve Operability	As Specified in 3.13
d.	Flow Rate at 150 psig.	Once/ operating cycle, verify that the HPCI pump delivers at least 4250 GPM for a system head corresponding to a reactor pressure of 150 psig.

The HPCI pump shall deliver at least 4250 GPM for a system head corresponding to a reactor pressure of 1000 to 150 psig.

LIMITING CONDITIONS FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

D. Reactor Core Isolation Cooling (RCIC) System

1. The RCIC system shall be operable whenever there is irradiated fuel in the reactor vessel, reactor pressure is greater than 150 psig, and reactor coolant temperature is greater than 365°F, except as specified in 3.5.D.2 below.

2. From and after the date that the RCIC system is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 14 days unless such system is sooner made operable, providing that during such 14 days the HPCIS is operable.

3. If the requirements of 3.5.D cannot be met, an orderly shutdown of the reactor shall be initiated and the reactor shall be in the Cold Shutdown Condition within 24 hours.

SURVEILLANCE REQUIREMENTS

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

D. Reactor Core Isolation Cooling (RCIC) System

1. HPCI system testing shall be as follows:

a.	Simulated Automatic Actuation Test	Once/ Operating Cycle
b.	Pump Operability	When tested as specified in 3.13, verify that the RCIC pump delivers at least 400 GPM at a system head corresponding to a reactor pressure of 1000 psig.
c.	Motor Operated Valve Operability	As Specified in 3.13
d.	Flow Rate at 150 psig.	Once/ operating cycle verify that the RCIC pump delivers at least 400 GPM at a system head corresponding to a reactor pressure of 150 psig.

The RCIC pump shall deliver at least 400 GPM for a system head corresponding to a reactor pressure of 1000 to 150 psig.

NRC STAFF

EXHIBIT 12

11.9 CONDENSATE STORAGE SYSTEM

11.9.1 Power Generation Objective

The power generation objective is to provide condensate for system makeup needs, and to take system "reject" surges.

11.9.2 Power Generation Design Basis

The condensate storage system shall provide station system makeup, receive system reject flow, and provide condensate for any continuous service needs and intermittent batch type services. The total stored design quantity shall be based on the demand requirements during refueling for filling the dryer separator pool and the reactor well.

Two tanks shall be used for reasons of operational flexibility so that a plant shutdown will not be required when one tank is being maintained.

11.9.3 Description

The two 275,000 gal condensate storage tanks supply the various station requirements as shown on Figure 11.9-1. The tanks are of coated carbon steel with all inlet and outlet lines, overflows, vents, and instrument lines located at the tank bottom or toward the tank center to prevent freezing problems. The condensate storage system also consists of the two condensate transfer pumps, a jockey pump, and associated piping and valves.

The condensate tanks provide the preferred supply to the HPCI and RCIC systems. The torus water storage provides the backup emergency HPCI and RCIC systems supply. All other suctions are located above the HPCI and RCIC suctions to provide a 75,000 gal reserve in each tank for these systems.

NRC STAFF

EXHIBIT 13

1.10 QUALITY ASSURANCE PROGRAM

1.10.1 Introduction

Boston Edison Company, as original owner and operator of Pilgrim Nuclear Power Station, assumed full responsibility and authority for facility operation and has taken appropriate action to ensure the station is designed, modified, operated, and maintained in accordance with sound engineering principles and safe operating practices. The Boston Edison Company Quality Assurance Program for operation of PNPS was defined in the Boston Edison Quality Assurance Manual Volume II (BEQAM).

The ownership and operation of PNPS was transferred From Boston Edison Company to the Entergy Nuclear Generation Company (ENGC), effective July 13, 1999.

The ENGC Quality Assurance Program for operation of PNPS was defined in the Pilgrim Quality Assurance Manual (PQAM), which was the governing document for quality related activities relating to Pilgrim Station until May 5, 2002, when the NRC approved ENGC's transfer of plant operating responsibility to Entergy Nuclear Operations Inc. (ENOI). At this time the PQAM was replaced by adopting the Entergy QA Program Manual (QAPM), as the QA program description for PNPS.

The requirements in the QAPM, and its Predecessors (BEQAM and PQAM), were established to comply with the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants."

1.10.2 QA Program Objectives

The quality assurance program's objectives are to ensure compliance with regulatory requirements, company commitments, and established practices for efficient design, modification, maintenance, testing, and operation of Pilgrim Station. The program requires every person involved in quality assurance program related activities to comply with the provisions of the program.

1.10.3 QA Program Organization

The function of the Pilgrim Quality Assurance Organization established by Entergy is to monitor the quality oriented activities of all organizations involved in the design, modification, operation, and maintenance of Pilgrim Station and report the results of such monitoring activities to the appropriate levels of management.

The site quality assurance organization reports off-site to the Entergy Director, Oversight. The Director, Oversight through the VP, Oversight reports to the President, Planning, Development and Oversight and the Chief Executive Officer. This reporting relationship ensures the appropriate organizational freedom required by 10 CFR 50 Appendix B, Criteria I as needed for the site QA organization to effectively perform their assigned functions.

1.10.4 Quality Control and Assurance Measures

The degree to which quality control and assurance measures are assigned is a direct function of the safety and operating requirements of the various structures, systems, and components.

Essential equipment and nuclear systems are emphasized; however, nonessential and non-safety related systems and components may be included in the Quality Assurance Program to the extent necessary to assure reliability of station operation.

The quality assurance organization has developed an integrated system of planned audits, reviews, surveillances, inspections, and assessments in order to fulfill its responsibility for monitoring of QA Program implementation. The system has been designed to meet or exceed applicable regulatory, license, and national code or standard requirements. The audits, reviews, and surveillances are scheduled to provide comprehensive oversight and verification of all aspects of the QA Program and to provide management of the affected areas with continuous assessments of facility operation.

In addition to the commitments to NRC Regulatory Guides and ANSI Standards described in the Entergy QAPM, the following Regulatory Guides and associated ANSI Standards will be applied to construction related activities associated with major modifications during the operational phase that are comparable in nature and extent to related activities occurring during initial plan design and construction:

- Regulatory Guide 1.54, Rev. 0, 1973. "QA Requirements for Protective Coating Applied to Water-Cooled Nuclear Power Plants."
- Regulatory Guide 1.55, Rev. 0, 1973. "Concrete Placement in Category I Structures."
- ANSI N45.2.16, "Requirements for the Calibration and Control of Measuring and Test Equipment Used in the construction and Maintenance of Nuclear Power Generating Stations."

UFSAR, Appendix D describes the quality assurance program for the initial design and construction phase of Pilgrim Station.

1.10.5 Quality Records and Documentation

Documentation to support quality assurance is essential to the safe operation, integrity and proper maintenance of Pilgrim Station. It is compiled and maintained throughout the life of the plant. In general, the minimum requirements for documentation for PNPS are those requirements imposed by the QAPM.

Refer to Section 13.7.5 relative to records retention.

1.10.6 Quality Program Review

Periodic, independent reviews of the QA Program policies and implementation are conducted to evaluate the continued adequacy and effectiveness of the program.

1.10.7 QA Program Update

The QA Program applied to operation and modification of Pilgrim Station is set forth in the QAPM.

NRC STAFF

EXHIBIT 14

Entergy

Entergy Nuclear Operations, Inc.
Pilgrim Station
600 Rocky Hill Road
Plymouth, MA 02360

Stephen J. Bethay
Director, Nuclear Assessment

June 29, 2005

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

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

Pilgrim Fourth Ten-Year Inservice Inspection Program Plan, and the Associated Relief Requests for NRC Approval

LETTER NO: 2.05.045

Dear Sir or Madam:

By this letter Entergy submits the attached Pilgrim Nuclear Power Station (PNPS) Fourth Ten-Year Inservice Inspection (ISI) Program Plan (PNPS-RPT-05-001, Rev. 0) pursuant to 10 CFR 50.55a(a)(g)(4)(ii) and requests NRC approval of associated relief requests pursuant to 10 CFR 50.55a(a)(3).

PNPS Fourth Ten-Year ISI Interval will commence on July 1, 2005 and ends on June 30, 2015.

This ISI Program Plan is developed in accordance with the 1998 Edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI with the 2000 Addenda. The ISI Program Plan is divided into five major sections:

1.0 Introduction and Plan Description
2.0 ISI System / Component Exemptions & Examination Development
3.0 Code Compliance Inservice Inspection Program Summary
4.0 Inservice Inspection Components & Schedule
5.0 Appendices

The ISI Program Plan contains the Second Ten-Year IWE Containment Inspection program and Second Ten-Year Risk Informed ISI program. Both programs have been aligned with the regular ISI program interval schedule.

A047

The Code of Record for the Fourth Ten-Year ISI Interval, the Second IWE Containment Inspection interval, and the Second RI-ISI interval will be the ASME Section XI Code, 1998 Edition with 2000 Addenda. Accordingly, this letter requests NRC acceptance for these programs to be based upon the aforementioned Edition/Addenda.

Fourth Ten-Year ISI Relief Requests for NRC Approval:

The relief requests associated with the Fourth Ten-Year ISI Program Plan and any precedent are contained in Section 5, Appendix B of the Program Plan. There are thirteen (13) relief requests. Two (2) relief requests PRR-28 (MB6074) and PRR-39 (MC2496) were previously approved for use during the 4th interval are included for information. In addition, three (3) requests related to the use of subsequent editions and addenda of Section XI of the ASME Code are included in Appendix D.

Entergy requests NRC review and approval of the ISI Relief Requests as soon as possible, preferably by July 1, 2006.

This submittal represents ISI Program Plan and does not contain any regulatory commitments.

If you have any questions on this transmittal, please contact Mr. Bryan Ford, Licensing Manager at 508-830-8403.

Sincerely,

Stephen J. Bethay

Stephen J. Bethay

SJB/wgl

Attachment: 1. PNPS Fourth Ten-Year ISI Program Plan, including IWE Containment Inspection Program (PNPS-RPT-05-001, Rev. 0)

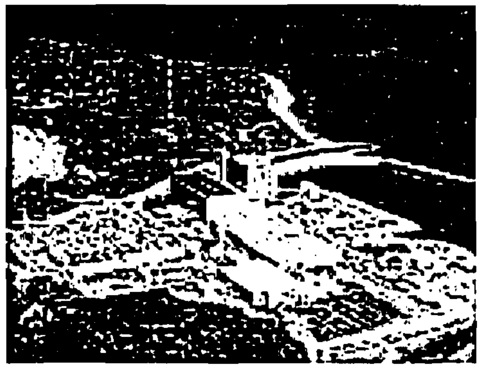
cc: Regional Administrator, Region 1
w/o U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Mr. James Shea, Project Manager
Project Directorate I
Mail Stop: 0-8B-1
Division of Licensing Project Management
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission

Senior Resident Inspector
Pilgrim Nuclear Power Station

Entergy
Nuclear Northeast

Entergy Nuclear Generation Company
PILGRIM NUCLEAR POWER STATION (PNPS)
Plymouth, Massachusetts



ASME B&PV CODE SECTION XI
FOURTH TEN-YEAR INSPECTION INTERVAL
INSERVICE INSPECTION (ISI) PROGRAM PLAN

July 1, 2005 to June 30, 2015

Commercial Service Date:	**June 8, 1972**
NRC Docket Number:	**50-293**
Facility Operating License:	**DPR-35**
Document Number:	**PNPS-RPT-05-001**
Revision Number:	**0**
Document Date:	**July 1, 2005**

Prepared by:
Entergy Nuclear Northeast
440 Hamilton Avenue
White Plains, New York 10601

One of the tasks required to complete the Third Interval ISI Program Update at the Pilgrim Nuclear Power Station was to perform a review of the classification boundaries for inservice inspections. This was documented under Vectra Report 0025-00241-001. Vectra documented the information and decisions in developing recommended and required revisions to the ISI boundaries for clarification purposes.

1.3.1 Code of Federal Regulations (10CFR50)

Sections 50.55a(c), (d) and (e), reference 10CFR50.2, and Regulatory Guide 1.26 for the classification of Quality Group A, and Quality Groups B and C components, respectively. Footnote 9 of 10CFR50.55a specifically invokes Regulatory Guide 1.26. 10CFR50.2 provides criteria for the classification of Quality Group A components.

In accordance with 10CFR50.55a(c), the Class I boundaries are described in 10CFR50.2 which defines the reactor coolant boundary as follows:

"All those pressure-containing components of boiling and pressurized water-cooled nuclear power reactors such as pressure vessels, piping, pumps, and valves, which are:

(1) Part of the reactor coolant system, or

(2) Connected to the reactor coolant system, up to and including any and all of the following:

(i) The outermost containment isolation valve in system piping which penetrates primary reactor containment,

(ii) The second of two valves normally closed during normal reactor operation in system piping which does not penetrate primary reactor containment,

(iii) The reactor coolant system safety and relief valves.

For nuclear power reactors of the direct cycle boiling water type, the reactor coolant system extends to and includes the outermost containment isolation valve in the main steam and feedwater piping."

This is the definition which is used for Class I systems at Pilgrim Station.

1.3.2 Regulatory Guide 1.26

10CFR50.55a does not specifically define the boundaries for Class 2 and 3 piping systems, but in Footnote 9 it refers to Regulatory Guide 1.26 and NUREG-0800, Section 3.2.2 for guidance. For Pilgrim Station, guidance is taken from Regulatory Guide 1.26 which provides general boundary definitions for systems containing water, steam or radioactive waste. It should be noted that Regulatory Guide 1.26 specifically states that it does not address other systems such as "...instrument and service air, diesel engine and its generators and auxiliary support systems, diesel fuel, emergency and normal ventilation, fuel handling, and radioactive waste management systems".

1.3.3 ASME Section XI

In accordance with 10CFR50.55a, the inservice inspection of Class 1, 2 and 3 piping and components will be governed by ASME Section XI. When applying the criteria of ASME Section

XI, one of the main considerations is the exemption criteria presented in Paragraphs IWB-1220, IWC-1220 and IWD-1220 for Class 1, 2 and 3 systems respectively. These paragraphs state specific criteria for the exemption of components due to various factors including line size, system function and operating conditions. One exemption which requires particular attention is the exemption of Class 1 components due to make-up flow capacity as presented in IWB-1220(a). As addressed in BECo Boundary Study Document NED 90-300, attached NUTECH Letter No. BOS-06-01 1, and its associated make-up capacity calculation, Class I piping in water systems with an inside diameter of 1.10" or less, and piping in steam systems with an inside diameter of 2.20" or less qualify for the make-up capacity exemption of IWB1220(a).

ASME Section XI Examination Categories B-F and B-J currently contain the requirements for the nondestructive examination (NDE) of Class 1 piping components. The alternative RI-ISI program for piping is described Section 1.5.2.1 of this ISI Program Plan. The RI-ISI Program will be substituted for the Section XI program for Class 1 piping in accordance with 10CFR50.55a(a)(3)(i) by alternatively providing an acceptable level of quality and safety. Other non-related portions of the ASME Section XI Code will be unaffected. For example, existing pressure testing requirements and Class 2 piping inspection requirements remained unchanged. EPRI TR-1 12657 provides the methodology for defining the relationship between the RI-ISI program and the remaining unaffected portions of ASME Section XI.

1.3.4 Updated Final Safety Analysis Report (FSAR)

In general, the PNPS Updated Final Safety Analysis Report (FSAR) provides limited references to inservice inspection requirements. There are numerous references to inservice inspections interspersed throughout the FSAR, but most are inconsequential discussions on accessibility or testing requirements. FSAR Appendix K addresses the general requirements of Pilgrim's ISI Program, but it only covers the First Interval ISI Program. The PNPS FSAR does not establish any additional commitments which must be incorporated into the ISI Program.

1.3.5 NRC Commitments

In general, Pilgrim Station was designed and constructed prior to many of the Code and Regulatory documents becoming mandatory. The augmented examination requirements which have been issued since the start of plant operation are currently being performed at Pilgrim Station under PNPS Procedure No. NE15.08, "*Control of Augmented Examinations*". Although the documents listed in this procedure provide augmented examination requirements, they do not affect the inservice inspection boundaries.

1.3.6 ISI Classification & Flow Diagrams

The Inservice Inspection classification process described above resulted in system classifications indicating ASME Class 1, 2, 3, and MC components. Class boundaries were developed and are shown on the ISI flow diagrams (ISI P&IDs) listed in Appendix E Table E.1.

For ASME Class 1 components, the requirements of Subsection IWB apply; for ASME Class 2 components, the requirements of Subsection IWC apply; for ASME Class 3 components, the rules of Subsection IWD apply; and for ASME Class MC components, the requirements of Subsection IWE apply. The rules of Subsection IWF for component supports apply to ASME Classes 1, 2, 3, and MC.

1.4.4 The ASME Section XI Repair / Replacement Program will be implemented and maintained in accordance with separate plant site procedures. Repair and replacement requirements for Class MC components (Code Subsection IWE) are included within the site's Section XI Repair / Replacement Program.

1.5 Augmented and Alternative Inservice Inspection Requirements

1.5.1 Augmented Inservice Inspection Requirements

Augmented inservice inspection requirements are those examinations that are specified by documents other than the ASME Section XI Code. Augmented examinations will be performed as required by 10CFR50.55a, the NRC, Response to RAIs, or as deemed necessary by the ISI Program. The augmented inservice inspections performed at the Pilgrim Nuclear Power Station are documented in controlled PNPS Procedure No. NE15.08, "*Control of Augmented Examinations*", latest revision. Current augmented examination programs include:

1.5.1.1 Piping Flow-Accelerated Corrosion (FAC) Monitoring

Flow accelerated corrosion (FAC) examinations are performed in accordance within the separate and independent PNPS FAC Program under Specification M577. The PNPS FAC Program satisfies NRC G.L. 89-08 using the guidelines developed by NUMARC and EPRI. Credit is taken for 8 of the 71 RI-ISI components under the FAC Program. Coordination between the FAC Program and the RI-ISI Program is described in the PNPS RI-ISI Template and in Inservice Engineering Report No. PNPS-02Q-402. The FAC Program is relied upon to manage the flow accelerated corrosion damage mechanism in Class 1 piping, but is not otherwise affected or changed by the RI-ISI program.

The following table summarizes the relationship between the FAC and RI-ISI examinations. Note that some of the welds in this table are in carbon steel piping segments that are evaluated for FAC, but the welds are not selected for examination per the FAC Program. In these instances, welds selected for examination per the RI-ISI Program will require volumetric examination like any other weld.

FAC vs. RI-ISI EXAMINATIONS

RISK CAT.	SEGMENT	WELD NO.	EXAMINATION(S) REQUIRED	
			RI-ISI UT	FAC
2(I)	FW-003	6-N4A-12	X	X
2(I)	FW-002	6-N4A-13	X	X
2(I)	FW-005	6-N4B-11	X	X
2(I)	RPV-003	6-N4A-1	X	
2(I)	RPV-004	6-N4B-1	X	
2(I)	RPV-005	6-N4C-1	X	
2(I)	RPV-006	6-N4D-1	X	
2(I)	FW-005	6-N4B-8	X	
2(I)	FW-011	6-N4D-2	X	

FAC vs. RI-ISI EXAMINATIONS

RISK CAT.	SEGMENT	WELD NO.	EXAMINATION(S) REQUIRED	
			RI-ISI UT	FAC
2(I)	FW-013	6-N4C-2	X	
2(I)	FW-016	6-A-10	X	
2(I)	FW-016	6-A-12	X	
4(I)	MS-001	1-A-11		X*
4(I)	MS-001	1-A-12		X*
4(I)	FW-009	6-N4D-14		X*
4(I)	FW-009	6-N4D-15		X*
4(I)	FW-009	6-N4D-16		X*
4(I)	FW-012	6-N4C-11		X*
4(I)	RWCU-001	12-I-4		X*
4(I)	RWCU-001	12-I-5		X*
4(I)	RPV-010	1-D-1	X	
4(I)	MS-001	1-A-7	X	
4(I)	MS-001	1-A-8	X	
4(I)	MS-015	1-A-15	X	
4(I)	MS-016	1-B-15	X	
4(I)	MS-017	1-C-15	X	
4(I)	MS-018	1-D-15	X	

*The FAC Program examination is credited for these 8 RI-ISI components.

1.5.1.2 Salt Service Water (SSW) System Inspections

Routine inspection, maintenance, and test requirements for the PNPS Salt Service Water (SSW) System piping and heat exchanger inspections, along with the associated acceptance criteria, are included in Specification M591 for compliance with NRC G.L. 89-13. These inspections are separate from, but supplement, the Section XI Class 3 ISI component inspections listed in Table 4.1-18. Implementation of SSW System inspections is via PNPS Nuclear Organization Procedure NOP02E1 "Service Water Inspections, Maintenance, and Testing in Response to Generic Letter 89-13".

1.5.1.3 Class I Pressure Boundary Only (PBO) Piping & Components Augmented Inspection Program

1.5.1.3.1 Background & Purpose

During 1998 it was identified that there was not an adequate basis for the ISI boundary change from Class 3 to Class 0 at the Normally-Open RBCCW Non-Essential loop isolation valves. The RBCCW Non-Essential heat transfer components perform no active safety function but are categorized as PNPS Class I "Pressure Boundary Only" (PBO) and the non-essential piping, pipe supports, and components are "MQCI" per the PNPS Q-list. The

1.11.1.2 Class MC (IWA-4550)

Pressure testing following repair/replacement activities performed on Class MC items will be in accordance with IWE-5000.

1.11.2 Periodic System Pressure Testing

1.11.2.1 General

Periodic system pressure tests are performed by plant procedures in accordance with the requirements of Article IWA-5000 for the following components:

- Class 1 Pressure Retaining Components (Examination Category B-P)
- Class 2 Pressure Retaining Components (Examination Category C-H)
- Class 3 Pressure Retaining Components (Examination Category D-B)

The requirements of IWA-5000 are not applicable to Class MC components, except for repair/replacement activities. Article IWA-5000 System Pressure Tests are also not applicable to Subsection IWF component supports.

Test boundaries will be determined in accordance with IWA-5220.

The required visual examinations (VT-2) will be performed by personnel qualified and certified in accordance with Subarticle IWA-2300. Guidance for the PNPS ISI Inspectors when performing VT-2 visual inspections for leakage during the Class 1, Class 2, and 3 system pressure tests is provided by PNPS Procedure No. 2.1.8.3, "*Visual Examination for Leakage During System Pressure Testing*".

Tests will be documented by plant procedures and made available to an ANII inspector and a Plant NDE Level III inspector for review.

1.11.2.2 System Leakage Testing

In accordance with 10CFR50.55a(b)(2)(xx) "*System Leakage Tests*", when performing system leakage tests per IWA-5213(a), 2000 Addenda, a 10-minute hold time after attaining test pressure is required for Class 2 and Class 3 components that are not in use during normal operating conditions, and no hold time is required for the remaining Class 2 and Class 3 components provided that the system has been in operation for at least 4 hours for insulated components or 10 minutes for uninsulated components.

Class 1 System Leakage Testing shall be performed after every reactor refueling outage has been completed prior to plant startup.

Class 2 and Class 3 System Leakage Testing shall be performed once each Inspection Period.

The leakage observations shall be made by qualified VT-2 examiners. VT-2 Visual Examination Reports shall be generated and reviewed by site personnel in accordance with site procedures. Such reports are available for review by regulatory personnel.

1.11.2.3 Hydrostatic Testing

Class 1 (IWB) and Class 2 (IWC) components do not require hydrostatic testing under Examination Categories B-P and C-H, respectively.

Class 3 (IWD) components under the 1998 Code, 2000 Addenda, require 10 Yr. System Hydrostatic Tests (Exam. Cat. D-B, Item No. D2.20) to be conducted at or near the end of the Inspection Interval or during the same Inspection Period as the Third Interval. These System Hydrostatic Tests may be conducted while the plant is either in operation or shutdown. However, per 10CFR50.55a Request Number PIL-05-R-003 included within Appendix D, the 2001 Edition, through the 2003 Addenda will be used in place of the 1998 Edition, 2000 Addenda. Class 3 system hydrostatic test requirements have been deleted in their entirety from the 2001 Edition, 2003 Addenda.

1.12 Calibration Blocks

1.12.1 Calibration blocks shall meet the material, surface finish and calibration reflector configuration requirements in effect at the time of the calibration block fabrication. Where this differs from the current edition of ASME Section XI, the differences shall be noted in the UT examination procedure.

1.12.2 Calibration blocks shall be used to establish a reference sensitivity level from which subsequent examinations may be compared. The calibration block design may be the Basic Calibration Block described in Section XI Appendix III (i.e., III-3400) or the design may be the Alternative Calibration Block described in ENN NDE procedures. During Section XI Appendix VIII performance demonstration for ultrasonic examinations, alternate calibration blocks may be used.

1.12.3 A detailed list of all ISI calibration blocks to be employed during the Fourth Interval is provided in Appendix C of this Program Plan. Per PDI procedures, calibration blocks fabricated to an edition of Section XI earlier than the 1998 Edition with 2000 Addenda may be used in the 4th Interval without reconciliation.

NRC STAFF

EXHIBIT 15

ATTACHMENT 71111.07

INSPECTABLE AREA: Heat Sink Performance

CORNERSTONES: Initiating Events
Mitigating Systems
Barrier Integrity

INSPECTION BASES: Heat exchangers and heat sinks are required to remove decay heat, and provide cooling water for operating equipment. Degradation in performance can result in failure to meet system success criteria, and lead to increased risk primarily due to common cause failures. This inspectable area verifies aspects of the associated cornerstones for which there are no indicators to measure performance.

LEVEL OF EFFORT: The effort of this procedure consists of the review of a sample of one or two heat exchangers/heat sinks, on an annual basis, in accordance with the requirements specified in Section 02.01. On a biennial basis, review a sample of two or three heat exchangers/heat sinks in accordance with the requirements in Section 02.02.

71111.07-01 INSPECTION OBJECTIVES

01.01 To verify that any potential heat exchanger deficiencies which could mask degraded performance are identified. Applies to all heat exchangers connected to safety related service water systems.

01.02 To verify that any potential common cause heat sink performance problems that have the potential to increase risk are identified, i.e., icing at circulating and service water intake structures.

01.03 To verify that the licensee has adequately identified and resolved heat sink performance problems that could result in initiating events or affect multiple heat exchangers in mitigating systems and thereby increase risk, i.e., component cooling water heat exchanger performance affected by corrosion, fouling, or silting.

71111.07-02 INSPECTION REQUIREMENTS

When scheduling this inspection, inspectors should consider refueling outage and at-power maintenance schedules. The review should be to identify opportunities to observe infrequent activities associated with risk significant heat exchangers or service water inspections/testing (heat exchanger inspections and testing, internal service water pipe inspections).

02.01 Annual Review. Verify the readiness and availability of a sample of one or two heat exchangers/heat sinks by monitoring licensee programs, or invoking industry standards, and also, if necessary, checking critical operating parameters, and/or maintenance records. The readiness and availability of the sample of heat exchangers/heat sinks may be verified by one of the items a. through d. below. Items e. and f. may be performed as additional assurance of the heat exchanger(s) operability.

a. Observe actual performance tests for heat exchanger/heat sinks or review the data/reports for those tests for any obvious problems or errors.

b. Verify the licensee utilizes the periodic maintenance method outlined in EPRI NP-7552.

c. Observe licensee's execution of biofouling controls.

d. Observe the licensee's heat exchanger inspections and the state of cleanliness of their tubes.

e. Check, by either a walkdown or the review of operations data, any or all of the following:

   1. The heat exchanger's inlet and/or outlet temperatures.

   2. Primary or secondary side fluid flow.

   3. If there are any evident leaks.

   4. If licensee believes the heat exchanger can perform its safety related function and whether supporting documentation or inspections support the licensee's position.

f. Determine if heat exchanger is correctly categorized under the Maintenance Rule and verify if it is receiving the required maintenance.

02.02 Biennial Review

a. Select a sample of 2-3 heat exchangers for systems that are ranked high in the plant specific risk assessment. This includes all heat exchangers directly or indirectly connected to the safety-related service water system.

b. For the selected heat exchangers that are also directly connected to the service water system, verify that testing, inspection/maintenance, or monitoring of biotic fouling controls are singularly or in combination adequate to ensure proper heat transfer.

   1. Review the method and results of heat exchanger performance testing or equivalent methods to verify performance. Verify the following items, as applicable:

      (a) The selected test methodology is consistent with accepted industry practices, or equivalent.

      (b) Test conditions (e.g., differential temperatures, differential pressures, and flows) are consistent with the selected methodology.

      (c) Test acceptance criteria (e.g., fouling factors, heat transfer coefficients) are consistent with the design basis values.

      (d) Test results have appropriately considered differences between testing conditions and design conditions (functional testing at design heat removal rate may not be practical).

(e) Frequency of testing based on trending of test results is sufficient (based on trending data) to detect degradation prior to loss of heat removal capabilities below design basis values.

(f) Test results have considered test instrument inaccuracies and differences.

(g) Tube and shell side heat loads are equal if adequate information is available in test results to calculate these two values.

2. For inspection/cleaning, review the methods and results of heat exchanger performance inspections or observe the actual inspection/ cleaning. Verify the following first three steps ((a)-©)) if conducting the review and the last step (d) only if actually observing the inspection/cleaning:

(a) Methods used to inspect heat exchangers are consistent with expected degradation.

(b) Established acceptance criteria are consistent with accepted industry standards, or equivalent, including acceptability of the cleaning interval.

(c) As found results are appropriately dispositioned such that the final condition is acceptable.

(d) If observing the inspection/cleaning then perform the following:

(1.) Prior to cleaning, inspect the extent of fouling and blockage of tubes.

(2.) Inspect the condition of the cleaned surfaces.

(3.) Verify that the number of plugged tubes are within the limit of operability of the heat exchanger and are appropriately accounted for in heat exchanger performance calculations.

3. When implemented, verify that chemical treatments, tube leak monitoring, methods used to control biotic fouling corrosion (such as shells, seaweed, corbicula, and microbiological induced corrosion), and methods to control macrofouling (silt, dead mussel shells, debris, etc.) are sufficient (e.g., appropriate acceptance criteria) to ensure required heat exchanger performance.

c. For the selected heat exchangers <u>either directly or indirectly connected, except as noted,</u> to the service water system, verify the following:

1. Condition and operation are consistent with design assumptions in heat transfer calculations, e.g. for tube plugging.

2 Licensee has evaluated the potential for water hammer in those heat exchangers and undertaken appropriate measures to address it.

3. The heat exchangers do not exhibit excessive vibration during operation that could potentially damage their tubes or tubesheets based on direct observation or issues identified in corrective-action documents.

4. For heat exchangers indirectly connected to the service water system, that the water chemistry is being adequately controlled to discourage corrosion, e.g. stress corrosion cracking, in its metallic sub-components.

5. Redundant and infrequently used heat exchangers are flow tested periodically at maximum design flow.

d. Verify the performance of ultimate heat sinks (UHS) and their subcomponents like piping, intake screens, pumps, valves, etc. by tests or other equivalent methods. For heat sinks, the issue is their availability and accessibility to the in-plant cooling water systems.

The inspector should check at least two of the following for heat sinks and their subcomponents as applicable. (For plants that have dams or other containment devices for the UHS, items 1 or 2 below must be checked every other biennial assessment.)

1. For an above-ground UHS encapsulated by embankments, weirs or excavated side slopes:

    a. The toe of the weir or embankment should be checked for seepage of water and the crest of the dam should be checked for settlement.

    b. The rip rap protection placed on excavated side slopes should be in place. Ensure that if vegetation is present along the slopes that it is trimmed, maintained and is not, or has not, adversely impacted the embankment.

    c. If available, review the licensee or third party dam inspections that monitor the integrity of the heat sink.

    d. Verify sufficient reservoir capacity.

2. For underwater UHS weirs or excavations, perform or verify visual or other inspections have been performed to check for:

    a. Any possible settlement or movement indicating loss of structural integrity and/or capacity.

    b. Sediment intrusion that may reduce capacity.

3. Review design changes to the ultimate heat sink.

4. Free from clogging due to macrofouling (silt, dead mussel shells, debris, etc.) and aquatic life such as fish, algae, grass or kelp.

5. Licensee has in place adequate controls for biotic fouling.

6. Functionality during adverse weather conditions, e.g. icing or high temperatures.

7. Performance tests for pumps and valves in service water system.

e. Review, if available, eddy current summary sheets, ultrasonic testing results, and visual inspections to determine the structural integrity of the heat exchanger.

02.03 Identification and Resolution of Problems. Verify that the licensee has entered significant heat exchanger/sink performance problems in the corrective action program. As it relates to degraded heat exchanger/sink performance including issues related to silting, corrosion, fouling, and heat exchanger testing then verify that licensee corrective actions are appropriate. See Inspection Procedure 71152, "Identification and Resolution of Problems," for additional guidance.

71111.07-03 INSPECTION GUIDANCE

General Guidance

Refer to the table below for selecting inspection activities to achieve each cornerstone objective and to those activities that have a risk priority i.e., those common-cause failures with a reasonable probability of occurring should be targeted by inspection to determine impact on cornerstones.

Cornerstone	Inspection Objective	Risk Priority	Example
Initiating Events	Evaluate events, issues, or conditions involving the degradation or loss of both the normal and ultimate heat sinks.	Common-cause issues affecting heat removal capabilities.	Icing of a circulating water and service water intake structure.
Mitigating Systems/ Barrier Integrity	Evaluate any potential degraded performance of heat exchangers/ containment fan coolers	Heat exchanger selection should focus on the potential for common-cause failures or on potentially high risk heat exchangers with a low margin to their design point or the high potential for fouling.	Degraded containment cooling or component cooling water heat exchanger performance due to corrosion, fouling, silting, etc.

Specific Guidance

03.01 Annual Review

This inspection should encourage the timely identification of heat exchanger/heat sink performance problems so the licensee may take prompt corrective actions.

- The heat exchangers should be in a system that is directly or indirectly cooled by the safety-related service water system or the credited water system cooled by the ultimate heat sink, and that is ranked high in the plant specific risk assessment.

- The inspection activities in some cases may be the same as those in Section 02.02 but the inspection should not be conducted at the same level of detail or depth.

- Inspection results are appropriately categorized against pre-established engineered acceptance criteria, and are acceptable.

- Frequency of testing or inspection is sufficient (given the potential for fouling) to detect degradation prior to loss of heat removal capabilities below design basis values.

a. These tests should be those typically sanctioned by industry. The heat exchangers should be in a system that is directly cooled by the safety-related service water system or the credited water system cooled by the ultimate heat sink. Test acceptance criteria and results have appropriately considered differences between testing conditions and design conditions (functional testing at design heat removal rate may not be practical); and the test results have appropriately considered test instrument inaccuracies and differences.

b. No specific guidance

c. The licensee should have an acceptance criteria for its bio-fouling controls that is based on an industry standard, supportive program results, or the recommendation of the appropriate vendors.

d. Primarily focus on whether the number of tubes plugged affects the heat exchanger's operability and not the biofilm on the inside of tubes which should be covered in the biennial inspection by a specialist. The licensee should have an acceptance criteria that indicates the maximum number of tubes that may be clogged for a specific heat exchanger and a basis for that acceptance criteria.

03.02 <u>Biennial Review</u>

a. There is no limitation on the type and size of heat exchangers that can be selected as long as they are cooled by the safety-related service water system or the credited water system cooled by the ultimate heat sink and they are ranked high in the plant specific risk assessment. The credited water source is the one relied on in accident analyses in the licensee's safety analysis report. The selection of the heat exchanger also should consider results from previous annual inspection and heat exchangers with past history of problems/extensive corrective actions.

b. For this requirement, if possible, focus on the credited water source as defined in 03.02a. above. Of the heat exchangers selected only those directly cooled by the safety-related service water system should be reviewed or evaluated for this inspection requirement in accordance with Generic Letter 89-13.

   1. No specific guidance

      (a - c) No specific guidance

      (d). Test results need to be extrapolated to the heat exchanger design conditions.

      (e) Trending of the results of heat exchanger performance tests should not have abrupt step changes without the licensee providing some valid justification as to the reason for the deviation..

      (f) Test instruments should be calibrated and set on appropriate range for the parameters to be measured, otherwise small measurement errors could affect the test results. The required accuracy of the instruments depends on the margins available between the calculated parameter based on the test results and the limiting design condition.

      (g) No specific guidance

   2. No specific guidance

3. No specific guidance

c. This inspection requirement should target those design and operational requirements other than those evaluated by performance testing or inspection/cleaning.

   1. The inspector can refer to either design assumptions in calculations or also parameters on design data sheet that can be evaluated by observation not testing.

   2. No specific guidance

   3. No specific guidance

   4. This inspection requirement is only applicable to those heat exchangers cooled by safety-related service water or the credited water source as defined above in 03.02a. and which are also in closed loop systems.

   5. No specific guidance

d. For this requirement focus on the credited water source as defined in 03.02a. above. The inspector should assess whether the ultimate heat sink and its subcomponents are capable of performing their intended safety functions. Only two of the listed parameters which are applicable for the respective plant should be reviewed on a biennial basis. For plants that have dams or other containments for the UHS, the inspection frequency is no longer always optional. This is based on findings concerning capacity and structural integrity on a facility with an UHS dam. Consideration for more frequent inspection should be made if there is known or suspected degradation. If the UHS is not licensee owned, ensure advance notice is provided to allow preparations for visual inspection if desired.

   1. Inspection of above ground UHS embankments, where they exist, should identify:

      a. Erosion which could lead to loss of structural integrity.

      b. Loss of shoreline protection can lead to a changing shoreline resulting in UHS capacity that is less than the design. Large vegetation, such as tree roots or burrowing animals can weaken the integrity of the embankments. Similarly, decayed tree roots can allow formation of a water channel in the embankment that weakens the integrity.

      c. If available, review licensee or third party dam inspections for integrity of heat sink.

      d. Changing shore lines or sediment intrusion can reduce UHS capacity. Lessons learned from plant inspections include: degradation of the shoreline by vegetation growth can cause compacted clay to degrade and slump into the heat sink reducing capacity, also an insufficient number of measurements taken of the depth of water may not identify significant debris or sediment build-up in the UHS.

   2. Inspection of underwater UHS structures should identify settlement or movement indicating loss of structural integrity and/or capacity. The height of water over the crest of the weir should be constant in cases where the licensee takes these measurements to verify capacity.

3. Review of changes or modifications should ensure that key design basis requirements were considered as inputs and maintained. Consideration may be given to reviewing planned modifications as well as age-related changes that have the potential to adversely impact the UHS design basis including intake structures, reservoir and dam material conditions.

4. This requirement can be satisfied by test results, observation, or other equivalent methods that verify ultimate heat sink and subcomponents can accommodate maximum system flow. Operating experience in 2004 and 2005 indicates a number of events involving foreign material intrusion into the systems. These events include clogging of system piping, heat exchangers and strainers due to overpopulation of small fish that are pulled into the system, underwater grasses and kelp that break off or die, and sediment intrusion. Generic Letter 89-13 recommended once per refueling outage visual inspection for macroscopic biological fouling, sediment and corrosion and removal of accumulation. Some licensees have made commitments pursuant to Generic Letter 89-13 to minimize the potential for clogging equipment.

5. Best verified by checking conformance with the acceptance criteria adopted by the licensee for checking the adequacy of the licensee's biotic fouling controls.

6. This inspection requirement should determine whether licensee has procedures to deal with adverse weather conditions. Coordinate the performance of this step with the inspection requirements of IP 71111.01, "Adverse Weather Protection." Also, this inspection should verify that the UHS water temperature is monitored and has not exceeded licensing or design basis.

7. No specific guidance.

e. No specific guidance

03.03 Identification and Resolution of Problems

The inspector should focus on events or conditions that could cause the loss of a heat exchanger/sink due to events such as heat transfer problems, improper cleaning, ice buildup, grass intrusion, or blockage of pipes and components. The inspector should determine whether the licensee has appropriately considered common-cause failures. If any loss of heat exchanger/sink events have occurred, these should receive the priority for review. Review the corrective actions to determine if actions were sufficient to prevent recurrence of the problem. Refer to IP 71152, "Identification and Resolution of Problems," for further guidance in this area.

71111.07-04 RESOURCE ESTIMATES

This inspection procedure is estimated to take, on average, 5 to 7 hours for an annual review and 34 to 46 hours for a biennial review at a site regardless of the number of units at that site. These estimates depend on the number of heat exchangers/sinks tested by the licensee during the inspection period.

71111.07-05 PROCEDURE COMPLETION

Inspection of the minimum sample size will constitute completion of this procedure in the Reactor Programs Systems (RPS). That minimum sample size will consist of one sample, on an annual basis, to verify the readiness/availability of one heat exchanger/heat sink per Section 02.01, and two samples, on a biennial basis, to verify the heat exchanger/heat sink performance in accordance with Section 02.02.

71111.07-06 REFERENCES

EPRI NP-7552 Heat Exchanger Performance Monitoring Guidelines (Call the NRC Technical Library to get a copy of this if needed.)

ASME OM-S/G Part 21 Inservice Performance Testing of Heat Exchangers in Light-Water Reactor Power Plants

NUREG 1275 Vol. 3 Operating Experience Feedback Report- Service Water System Failures and Degradations

NUREG/CR-5865 Generic Service Water System Risk-Based Inspection Guide

NUREG/CR-0548 Ice Blockage of Water Intakes

Generic Letter 89-13 Service Water System Problems Affecting Safety-Related Equipment

IN 2004-07 Information Notice: Plugging of Safety Injection Pump Lubrication Oil Coolers with Lakeweed

RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants

See the following web links for reference documents:

http://www.internal.nrc.gov/IRM/LIBRARY/standards/ihs.htm

http://www.internal.nrc.gov/IRM/LIBRARY/library.htm

http://www.nrc.gov/reading-rm/doc-collections/nuregs/

http://www.nrc.gov/reading-rm/doc-collections/reg-guides/

http://www.nrc.gov/reading-rm/doc-collections/gen-comm/

http://www.nrc.gov/reading-rm/doc-collections/gen-comm/info-notices/2004/

http://www.nrc.gov/reading-rm/doc-collections/reg-guides/power-reactors/active/

END

ATTACHMENT 1

Revision History for IP 71111.07

Commitment Tracking Number	Issue Date	Description of Change	Training Required	Training Completion Date	Comment Resolution Accession Number
	05/25/06	Researched commitments back four years - none found.	None	N/A	N/A
	05/25/06	Revised to incorporate lessons learned from ANO inspection regarding UHS dam integrity (report number 2005008); FB-937. Inspections of the UHS water reservoir is required every other biennial inspection. Also, addressed FB-996 regarding inspections to prevent clogging of UHS equipment with sediment. Other minor editorial comments also included.	None	N/A	ML061290102

NRC STAFF

EXHIBIT 16

May 12, 2006

Mr. Michael A. Balduzzi
Site Vice President
Entergy Nuclear Operations, Inc.
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360-5508

SUBJECT: PILGRIM NUCLEAR POWER STATION - NRC INTEGRATED INSPECTION REPORT 05000293/2006002

Dear Mr. Balduzzi:

On March 31, 2006, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Pilgrim reactor facility. The enclosed integrated inspection report documents the inspection findings, which were discussed on April 6, 2006, with Mr. Dietrich and members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one finding of very low safety significance (Green), which involved a violation of NRC requirements. However, because of the very low safety significance and because the issue has been entered into your corrective action program, the NRC is treating the issue as a non-cited violation (NCV), in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally, a licensee-identified violation that was determined to be of very low safety significance is listed in Section 4OA7 of this report. If you contest any NCV in this report, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the U.S. Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at Pilgrim.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document

Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA by Tracy Walker for Clifford Anderson/

Clifford Anderson, Chief
Projects Branch 5
Division of Reactor Projects

Docket No. 50-293
License No. DPR-35

Enclosure: Inspection Report 50-293/06-02
w/Attachment: Supplemental Information

cc w/encl: G. J. Taylor, Chief Executive Officer, Entergy Operations
M. Kansler, President, Entergy Nuclear Operations, Inc.
J. T. Herron, Senior Vice President and Chief Operating Officer
C. Schwarz, Vice-President, Operations Support
S. J. Bethay, Director, Nuclear Safety Assessment
O. Limpias, Vice President, Engineering
J. F. McCann, Director, Licensing
C. D. Faison, Manager, Licensing
M. J. Colomb, Director of Oversight, Entergy Nuclear Operations, Inc.
B. S. Ford, Manager, Licensing, Entergy Nuclear Operations, Inc.
T. C. McCullough, Assistant General Counsel
S. Lousteau, Treasury Department, Entergy Services, Inc.
R. Walker, Department of Public Health, Commonwealth of Massachusetts
The Honorable Therese Murray
The Honorable Vincent deMacedo
Chairman, Plymouth Board of Selectmen
Chairman, Duxbury Board of Selectmen
Chairman, Nuclear Matters Committee
Plymouth Civil Defense Director
D. O'Connor, Massachusetts Secretary of Energy Resources
J. Miller, Senior Issues Manager
Office of the Commissioner, Massachusetts Department of Environmental Protection
Office of the Attorney General, Commonwealth of Massachusetts
Electric Power Division, Commonwealth of Massachusetts
R. Shadis, New England Coalition Staff
D. Katz, Citizens Awareness Network
Chairman, Citizens Urging Responsible Energy
J. Sniezek, PWR SRC Consultant
M. Lyster, PWR SRC Consultant

1R07 Heat Sink Performance (IP 71111.07B)

a. Inspection Scope (4 samples)

Based on a plant specific risk assessment, past inspection results, and recent operational experience, the inspectors selected a sample of four safety-related heat exchangers (HXs) for review: the B Reactor Building Closed Cooling Water (RBCCW) HX, the B Residual Heat Removal (RHR) room cooler, the High Pressure Coolant Injection (HPCI) room cooler, and the Reactor Core Isolation Cooling (RCIC) room cooler. The Salt Service Water (SSW) system, which provides cooling to the RBCCW HXs, was also reviewed, as was the RBCCW system, which provides cooling to the safety-related room cooler heat exchangers.

The inspector reviewed performance tests, periodic cleaning, eddy current inspections, chemical control methods, tube leak monitoring, the extent of tube plugging, potential water hammer analysis, operating procedures, maintenance practices. The inspector also confirmed that controls for the selected components conformed to Entergy's commitments to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The inspector compared the inspection results to the established acceptance criteria to verify that the results were acceptable and that the HXs operated in accordance with design. The inspector walked down the systems, structures, and components, and monitored a performance test of the B RBCCW HX. The inspectors reviewed system health reports and interviewed applicable system engineers.

The inspector confirmed that potential common cause heat sink performance problems that had the potential to increase risk were identified and corrected by Entergy. The inspector closely examined potential macro fouling (silt, debris, etc.) and biotic fouling issues. The inspector walked down the Salt Service Water intake, chlorination system, and other support and sub components of the Salt Service Water system to assess the material condition of these systems and components.

The inspector reviewed a sample of condition reports (CRs) related to the RBCCW HXs, the safety-related room coolers, and the SSW system to ensure that Entergy was appropriately identifying, characterizing, and correcting problems related to these systems and components. The documents that were reviewed are listed in the attachment to the report.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Licensed Operator Simulator Training

a. Inspection Scope (1 sample)

The inspector observed an evaluated licensed operator simulator training exercise on January 23, 2006. The training was performed using scenarios SES-148 and involved both operational transients and design basis events. The inspector evaluated both the crew's performance and evaluators' assessments in-terms of the crew meeting the scenario objectives, accomplishing the critical tasks, proper use of abnormal and emergency operating procedures, command and control, effective communication, and the crew's ability to implement the emergency plan in-terms of event classification and notification. The inspector reviewed the post-scenario critique and confirmed lessons learned and items for improvement were discussed with the crew to enhance future performance.

NRC STAFF

EXHIBIT 17

10.7 SALT SERVICE WATER SYSTEM

10.7.1 Safety Objective

The safety objective of the Salt Service Water (SSW) System is to provide a heat sink for the Reactor Building Closed Cooling Water (RBCCW) System under transient and accident conditions.

10.7.2 Safety Design Basis

1. The system is designed with sufficient redundancy so that no single active system component failure can prevent the system from achieving its safety objective.

2. The system is designed to continuously provide a supply of cooling water to the secondary side of the RBCCW heat exchangers adequate for the requirements of the RBCCW under transient and accident conditions.

10.7.3 Power Generation Objective

The power generation objective of the SSW System is to provide a heat sink for the RBCCW System and the Turbine Building Closed Cooling Water (TBCCW) System during planned operations in all operating states.

10.7.4 Power Generation Design Basis

The system is designed to function as the ultimate heat sink for all the systems cooled by the RBCCW and TBCCW during all planned operations in all operating states by continuously providing adequate cooling water flow to the secondary sides of the RBCCW and TBCCW heat exchangers.

10.7.5 Description

The entire SSW System shown on Figure 10.7-1 is designed in accordance with Class I criteria, and there is no Class II Seismic piping in the system. See Appendix C and Section 12.

The Service Water System consists of five vertical service water pumps located in the intake structure, and associated piping, valving, and instrumentation. The pumps discharge to a common header from which independent piping supplies each of the two cooling water loops, each loop consisting of one Reactor Building and one Turbine Building cooling water heat exchangers. Two division valves are included in the common discharge header to permit the SSW System to be operated as two independent loops. The water then returns to the bay from the outlet of the heat exchangers. The heat exchangers are valved such that they can be individually backwashed without interrupting system operation. Any marine growth occurring in the heat exchangers will be controlled by hypochlorination based upon residual chlorine content measured in the discharge headers.

Sample valves have been installed in each of the independent cooling water loops, between the pumps and the heat exchangers. These valves are to be used for the following purposes:

1. To obtain a grab sample of service water.

2. To provide access to the header for venting

Each service water pump has an automatic air vent to prevent water hammer. Pump bearings are marine cutlass type, suitable for sea water application and are lubricated by water as it rises through the pump column.

The following number of pumps will be used during each of the indicated modes:

	Number of Pumps
Normal Operations	1 to 4
Accident Conditions (LOCA)	2
Shutdown Conditions	4

The number of pumps required for normal operation is selected based on plant cooling needs and SSW inlet temperature. Pressure transmitters mounted at the discharge header provide indication in the control room to allow operators to monitor SSW pump performance.

Plant Technical Specifications originally described the minimum required SSW pump performance as 2700 gpm at 55 ft TDH. Actual SSW pump rated performance is 2700 gpm at 95 ft TDH and minimum required performance for in-service testing is defined as 2700 gpm at 87.5 ft TDH. These TDH values are for the pump bowl not including the 40 ft vertical pump column. The 55 ft value represents the minimum required pressure, in feet, measured at the centerline of the pump discharge piping (EL 23.9 ft) for a pump bowl operating at 2700 GPM at 87.5 ft TDH.

The sea water tide level used in accident analysis calculations is 7.1 ft below msl, the yearly astronomical minimum low tide. This is the value used for the design basis analysis of the minimum SSW system performance required to perform the emergency containment cooling function. This low tide occurs for short periods of time during the semidiurnal tidal variations once every year. For the SSW system performance analysis, this lowest tide level is assumed to be constant, thereby yielding a conservatively low SSW system flow rate during accident analyses that span a several day period. The SSW pumps are also assumed to be operating at their minimum performance thereby providing only the required 4500 gpm to the RBCCW heat exchanger.

The minimum sea water level for maintaining SSW pump rated performance is approximately 13 feet 9 inches below msl. This represents the lowest sea water at which a SSW pump bowl operating at its rated performance of 95 feet TDH at 2700 gpm will produce a discharge head of 55 feet at 2700 gpm as measured at EL 23.9 feet. The lowest postulated instantaneous sea water level is 10.1 feet below msl(Section 2.4.4.2) caused by a hurricane producing 110 mph winds blowing directly offshore during the same critical hour at which the yearly astronomical low tide occurs. At this lowest water level, the pumps are capable of maintaining rated performance which implies that they have adequate NPSH and submergence (to prevent vortexing). It is not appropriate to assume that this condition will exist long enough to require that it be the design basis for the long term emergency cooling function of the SSW system for which these pumps are assumed to be at their minimum required performance level.

The buried portions of the 22" nominal diameter discharge piping from the last flange connections in the Auxiliary Building piping vault to the end of the discharge pipes at the Seal Well opening have been provided with a Cured-In-Place-Pipe (CIPP) lining. The 240 ft total length Loop "A" lining was installed in RFO-14 and the 225 ft total length "B" lining was installed in RFO-13. The CIPP liner material consists of a tube composed of nonwoven polyester felt material that is saturated with either an isophthalic polyester resin and catalyst system (Loop "A") or epoxy resin and hardener system (Loop "B") with a polyurethane or polyethylene inner membrane surface. The liner has a nominal 1/2" installed thickness. The resulting configuration is a rigid resin composite pipe within the original pipe with no requirements for bonding between the pipes.

The Salt Service Water System is designed to provide a heat sink for the Reactor Building Closed Cooling Water System under accident and transient conditions. Section 14.5 describes the Containment Cooling System analysis for a design basis loss of coolant accident (LOCA) at both a salt water inlet temperature of 65°F and 75°F.

To ensure that the safety design basis in Section 10.7.2 is achieved, flow condition is improved by the addition of baffle plates in the west side service water bay and a rear sluice gate allows maintenance and operational flexibility. The gate is normally closed and does provide a barrier to common mode failures. It does not provide a separation function as the salt service water pump bay is a single bay. It was not sized to allow supply of a seawater pump.

To ensure that sufficient seawater flow is maintained through the RBCCW heat exchangers (minimum of 4500 gpm for each heat exchanger), motor-operated butterfly valves on the TBCCW heat exchanger outlets will automatically adjust to preset throttling positions and the RBCCW outlet valves will simultaneously open. Automatic adjustment of the outlet valves occur following a loss of coolant accident (LOCA) with a coincident Loss of Offsite Power (LOOP), or a LOCA with degraded voltage on the safety buses while being supplied from the startup transformer. If a LOCA occurs without a LOOP or degraded voltage condition, the heat exchanger outlet valves remain as-is. Manual adjustments of the outlet valves will be made by operators to achieve adequate cooling water flow.

The loss of AC power will trip all service water pumps and will close one of the two division valves in the common pump discharge header, effectively dividing the service water system into two independent loops. Two pumps would be connected to each loop. The two division valves are arranged to permit the fifth (middle) pump to be operated on either loop. The operator preselects the division valve to be closed and thereby determines which loop will be connected to the middle pump. Either valve can also be closed by a hand switch.

For the limiting design basis emergency condition, the Circulating Water System pumps (Section 11.6) are not operating. This assumption is based on the need for the containment heat removal function of the SSW System versus the Circulating Water System when the Main Condenser is not being used as the heat sink. For either emergency containment heat removal or normal shutdown cooling, the SSW System is the main heat sink for the reactor core decay heat only after the discharge of steam to the Main Condenser has stopped. For the bounding design basis LOCA (Section 14.5), it is only the RHR, RBCCW, and SSW Systems that provide containment heat removal. To maximize the containment heat removal from a single loop of these systems, when required, the circulating water pumps are secured so that the level in the SSW pumps bay(s) will be equal to the ocean tide level and unaffected by operation of the Circulating Water System.

There are a number of single failures that can result in a SSW System configuration where one SSW pump will be supplying flow to both trains of SSW during the first ten minutes of an accident. Should this occur, operators are then expected to align the SSW System for optimal performance by starting additional pumps and/or closing division valves as required. This mode of operation has been analyzed and determined to be acceptable.

The pumps are separated into two loops electrically. In the event of the loss of the preferred AC power source, the two SSW pumps on loop A are powered by diesel generator A. They provide cooling to RBCCW loop A (also powered by diesel generator A) which provides cooling to all Core Standby Cooling System components loaded on diesel generator A. The two salt service water pumps on loop B have the same relationship, both to their standby AC power source, diesel generator B, and to RBCCW Loop B. The fifth pump is loaded on a common emergency service bus which can be powered from either standby AC power source.

Initiation of standby AC power following loss of the preferred AC power source will automatically start at least one pump in each loop during normal conditions. Following a LOCA and loss-of-offsite power one and only one pump will start in each loop because of diesel load limitations. Additional pumps are started manually by the operator as additional cooling loads are established and diesel capacity is made available.

10.7.6 Safety Evaluation

The SSW System is designed with sufficient redundancy so that no single active system component failure nor any single active component failure in any other system can prevent it from achieving its safety objective. Two independent closed loops with full heat transfer capacity on each loop are provided.

The existence of single failures which place the SSW system in the mode of one pump supplying both trains of heat exchangers for the first ten minutes of an accident has been analyzed and found to be acceptable. Operator action is credited after ten minutes to realign the system for optimal performance.

The 22 inch discharge headers leave the Reactor Building at an elevation of 15 ft 7 in msl. The two parallel lines run approximately parallel to the shoreline with a 2.8 percent slope. At a point approximately in line with the edge of the intake structure the lines turn and then parallel the centerline of the discharge structure with a 1.98 percent slope. At an elevation of -6 1/2 ft msl the two discharge lines turn and enter the side of the discharge structure sealwell.

Detection of leakage in the Reactor Building auxiliary bay is provided by two water level detectors mounted in each area. The detectors provide control room personnel with early indication of flooding such that personnel can be dispatched to the area to identify the source and effect isolation.

Dewatering of a major pipe rupture is accomplished by two 14 inch drain lines in each area which direct the water to the torus compartment. The discharge of the drain lines is submerged in a water trough to ensure that a sufficient water seal exists between the torus compartment and the Reactor Building auxiliary bay. The drain line dewatering capacity is sized on the maximum possible flooding rate which results from a single failure in any one line.

Numerous small diameter floor drains in the RBCCW compartments are plugged to prevent chloride and nitrate intrusions in radwaste. Therefore, normal leakage can accumulate to a level of four inches before overflowing the lip around the fourteen inch dewatering lines located in each of the RBCCW compartments. All safety related equipment in the RBCCW compartments will be unaffected by flooding four inches above the floor level. Normal leakage will not prevent safety related systems or components from performing their intended safety functions.

A major pipe break in this area will not result in a loss of both RBCCW and TBCCW Systems because the redundant portions of each system are separated by a watertight barrier. The watertight barrier consists of a watertight door and a spray barrier. The spray barrier is located in the pipeway immediately above the watertight door. Position switches provide station personnel with status information for the watertight door at all times.

In order to evaluate Pilgrim Station's susceptibility to damage due to a major oil spill in Cape Cod Bay near the Pilgrim Nuclear Power Station, previous oil spills have been examined relative to power plant and industrial proximity to the spill and the effects observed. Additionally, the various mechanisms by which spilled oil can be transported in water have been analyzed relative to the station design. The basis for these comparisons was Systems Study of Oil Cleanup Procedures (Dillingham Corporation, 1969) and the American Petroleum Institute (API) Conference on Prevention and Control of Oil Spills (December 1969).

Floating oil would be prevented from entering the intake structure by various devices. The primary oil containment device of the intake structure is its entrance skimmer wall, which functions as a submerged baffle. Minimum submergence of the baffle is 5 ft at design low water level. A secondary oil containment device is a concrete baffle wall inside the intake structure, downstream from the trash racks and upstream of the traveling screens and pumps. This baffle provides 2.2 ft submergence at mlw level. The final and most effective oil containment devices in the intake structure are the sluice gates through which the service water pump suction water must flow. The sluice gates are designed to allow isolation and dewatering of either circulating water bay. Positioning of the gates halfway closed would allow effective baffling to a submergence of 5 ft at design low water level.

In the unlikely event of some oil penetrating the aforementioned barriers, the minimum submergence at design low water level of the service water pumps of 11 ft would prevent the oil from being drawn into the pump suction.

Should slight amounts of emulsified oil reach the salt service water pump suction the observable effects would be limited to a small decrease in pumping efficiency and higher system head losses due to slightly increased fluid viscosity.

10.7.7 Inspection and Testing

Testing is performed on the SSW pumps, safety related check valves, and all safety related motor and air operated valves in the SSW system in accordance with the In-Service Testing (IST) program. The testing is performed per the ASME code as required by 10 CFR 50.55a(f), to demonstrate compliance with plant technical specifications for the SSW pumps. Operational performance testing is also conducted on the SSW system to verify that the system meets design criteria. Examinations are conducted on SSW system components in accordance with the In-Service Inspection (ISI) program.

10.7.8 Nuclear Safety Requirements for Plant Operation

General

This section represents the nuclear safety requirements for the SSW System for each BWR operating state which result from the stationwide BWR systems analysis of Appendix G. The following referenced portions of the safety analysis report provide important information justifying the entries in this section:

Reference	Information Provided
1. Section 10.7.5	Description of the SSW System hardware
2. Station Nuclear Safety Operational Analysis, Appendix G	Identifies conditions and events for which SSW System action is required

Each detailed requirement in the following analysis is referenced, if possible, to the most significant station condition originating the need for the requirement by identifying a matrix block on Table G.5-3. The matrix block references are given in parentheses beneath the detailed requirements in the "minimum required for action" section. The matrix block references identify the BWR operating state, the event number and the system number. For example, F39-99, identifies BWR operation state F, event (row) No. 39, and system (column) No. 99, on Table G.5-3.

System Action

The SSW System provides a heat sink for the RBCCW System.

Number Provided by Design

This system consists of two open loops. Each loop has two pumps (plus a common spare), piping, valving, instrumentation, and controls as necessary to provide coolant to one RBCCW heat exchanger and one TBCCW heat exchanger on each loop.

Minimum Required for Action

BWR Operating States A, B, C, D, E, & F:
Two pumps with associated controls and instrumentation on one loop must be operable and the following valves on that loop operable:

1. One TBCCW heat exchanger outlet valve unless valve is throttled

2. One RBCCW heat exchanger outlet valve unless valve is open

3. One discharge header valve (for loop separation unless valve is fully closed

(A35-99)	(B35-99)
(C39-99)	(D39-99)
(E39-99)	(F39-99)

10.7.9 Current Technical Specifications

The current limiting conditions for operation, surveillance requirements, and their bases are contained in the Technical Specifications referenced in Appendix B.

NRC STAFF

EXHIBIT 18

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

November 7, 1991

TO: ALL NUCLEAR POWER REACTOR LICENSEES AND APPLICANTS

SUBJECT INFORMATION TO LICENSEES REGARDING TWO NRC INSPECTION MANUAL SECTIONS ON RESOLUTION OF DEGRADED AND NONCONFORMING CONDITIONS AND ON OPERABILITY (GENERIC LETTER 91-18)

The NRC staff has issued two sections to be included in Part 9900, Technical Guidance, of the NRC Inspection Manual. The first is, "Resolution of Degraded and Nonconforming Conditions." The second is, "Operable/Operability: Ensuring the Functional Capability of a System or Component." Copies of the additions to the NRC Inspection Manual (enclosure) are provided for information only. No specific licensee actions are required.

The additions to the NRC Inspection Manual are based upon previously issued guidance. However, because of the complexity involved in operability determinations and the resolution of degraded and nonconforming conditions, there have been differences in application by NRC staff during past inspection activities. Thus, the purpose of publishing this guidance is to ensure consistency in application of this guidance by the NRC. Regional inspection personnel have been briefed on this guidance. The NRC will conduct further training on these topics to ensure uniform staff understanding.

The use of this guidance by inspectors may raise backfitting issues for specific licensees. The NRC backfitting procedures apply in such cases. Licensees should consult with the Regional office regarding the application of specific staff positions in the guidance.

Please contact the appropriate NRC Project Manager if you have any questions regarding this matter.

J G Partlow
James G. Partlow
Associate Director for Projects
Office of Nuclear Reactor Regulation

See Jacket

Enclosure: As stated

IDR-5
GL

9111040293 updated on 11/20/91
PDR ADOCK 05000003 Q 911107

NRC STAFF

EXHIBIT 19

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, DC 20555-0001

September 26, 2005

NRC REGULATORY ISSUE SUMMARY 2005-20: REVISION TO GUIDANCE FORMERLY CONTAINED IN NRC GENERIC LETTER 91-18, "INFORMATION TO LICENSEES REGARDING TWO NRC INSPECTION MANUAL SECTIONS ON RESOLUTION OF DEGRADED AND NONCONFORMING CONDITIONS AND ON OPERABILITY"

ADDRESSEES

All holders of operating licenses for nuclear power reactors, including those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

INTENT

The U.S. Nuclear Regulatory Commission (NRC) is issuing this Regulatory Issue Summary (RIS) to inform licensees that it has revised the guidance contained in two sections of NRC Inspection Manual Part 9900, Technical Guidance, "Operable/Operability: Ensuring the Functional Capability of a System or Component" and "Resolution of Degraded and Nonconforming Conditions," and has combined these two documents into a single document. The revised inspection guidance reflects relevant changes that have been made to NRC regulations, policies, and practices, and clarifies selected issues based on operating experience. This RIS requires no action or written response on the part of an addressee.

BACKGROUND INFORMATION

The NRC staff inspection guidance contained in the two NRC Inspection Manual sections described above were initially provided to licensees in Generic Letter (GL) 91-18, issued on November 7, 1991. The NRC staff revised the guidance in NRC Inspection Manual Part 9900, Technical Guidance, "Resolution of Degraded and Nonconforming Conditions," and issued it in Revision 1 of GL 91-18 on October 8, 1997. The purpose of Revision 1 of GL 91-18 was to more explicitly discuss the role of the 10 CFR 50.59 evaluation process in the resolution of degraded and nonconforming conditions.

In the summer of 2003, the NRC staff sought public comment on the technical guidance, which included holding a public workshop in August 2003. The staff revised the guidance based on the inputs received, and held a second public workshop to discuss it in August 2004. Subsequently, the NRC staff met several times in 2005 with an industry task force formed by the Nuclear Energy Institute (NEI), and resolved the comments received from various stakeholders.

ML052020424

SUMMARY OF ISSUE

Attached is a revised NRC Inspection Manual, Part 9900, Technical Guidance, "Operability Determinations & Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety." This guidance supercedes the guidance previously provided in GL 91-18 and Revision 1 to GL 91-18.

The attached inspection manual section provides guidance to NRC inspectors for reviewing the actions of licensees pertaining to the operability of structures, systems, and components (SSCs) following the discovery of degraded and nonconforming conditions in SSCs. However, many licensees have found NRC's guidance to be very useful in developing their plant-specific processes, and therefore the NRC staff is communicating it to licensees as a RIS.

The NRC revised its inspection guidance to reflect ongoing regulatory changes, including implementation of the revised reactor oversight process, the requirement that licensees appropriately assess and manage risk related to proposed maintenance activities (10 CFR 50.65(a)(4)), and implementation of the revised change control process in 10 CFR 50.59, "Changes, Tests and Experiments." The revision also clarifies selected issues in the guidance based on operating experience and industry feedback.

In addition, the NRC concluded that the two inspection manual documents were closely related. The NRC staff therefore combined the documents, and at the same time re-wrote them to make them clearer and more process-oriented. However, the NRC understands that licensees may collectively refer to the processes described in the revised Part 9900 as the "GL 91-18 process" or the "operability determination process (ODP)."

BACKFIT DISCUSSION

This RIS requires no action or written response and, therefore, is not a backfit under 10 CFR 50.109. Consequently, the staff did not perform a backfit analysis.

FEDERAL REGISTER NOTIFICATION

A notice of opportunity for public comment was published in the *Federal Register* on August 3, 2004 (69 FR 46599), to give interested parties an opportunity to suggest ways for improving the guidance. The staff concludes that this RIS and the attached NRC inspection guidance are informational and pertain to a staff position that does not represent a departure from current regulatory requirements and practices.

SMALL BUSINESS REGULATORY ENFORCEMENT FAIRNESS ACT OF 1996

This RIS is not a "rule" as defined in 5 U.S.C. 804 and therefore is not subject to the Congressional review provisions of the Small Business Regulatory Enforcement Fairness Action of 1996.

PAPERWORK REDUCTION ACT STATEMENT

This RIS does not contain any information collections and, therefore, is not subject to the requirements of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.). The information collection requirements referenced in Manual Chapter 9900 are approved by the Office of Management and Budget approval number 3150-0011 which expire February 28, 2007. The NRC may not conduct or sponsor, and a person is not required to respond to, an information collection unless the requesting document displays a currently valid OMB control number.

CONTACT

Please direct any questions about this matter to the technical contacts listed below, or to the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

/RA/
Patrick L. Hiland, Chief
Reactor Operations Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

Technical Contacts: Carl S. Schulten, NRR
301-415-1192
E-mail: css1@nrc.gov

James M. Trapp, (R-I)
610-337-5186
E-mail: jmt1@nrc.gov

Randall A. Musser, (R-II)
919-362-0601
E-mail: rxm1@nrc.gov

Stephen C. Burton, III, (R-III)
920-388-3156
E-mail: sxb3@nrc.gov

Charles R. Stancil, Jr., (R-IV)
817-276-6532
E-mail: crs1@nrc.gov

Attachment: NRC Inspection Manual Part 9900: Technical Guidance, "Operability Determinations & Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse To Quality or Safety"

Note: NRC generic communications may be found on the NRC public website, http://www.nrc.gov, under Electronic Reading Room/Document Collections.

C.12 Operational Leakage From Code Class 1, 2, and 3 Components

Leakage from the reactor coolant system, as specified in TSs, is limited to specified values in the TSs depending on whether the leakage is from identified, unidentified, or specified sources such as the steam generator tubes or reactor coolant system pressure isolation valves. If the leakage exceeds TS limits, the LCO must be declared not met and the applicable conditions must be entered. For identified reactor coolant system leakage within the limits of the TS, the licensee should determine operability for the degraded component and include in the determination the effects of the leakage on other components and materials.

Existing regulations and TSs require that the structural integrity of ASME Code Class 1, 2, and 3 components be maintained in accordance with the ASME Code. In the case of specific types of degradation, other regulatory requirements must also be met. If a leak is discovered in a Class 1, 2, or 3 component in the conduct of an inservice inspection, maintenance activity, or facility operation, corrective measures may require repair or replacement activities in accordance with IWA-4000 of Section XI. In addition, the leaking component should be evaluated for flaws according to IWB-3000, which addresses the analytical evaluation and acceptability criteria for flaws.

The TSs do not permit any reactor coolant pressure boundary (RCPB) leakage. The operational leakage LCO must be declared not met when pressure boundary leakage is occurring. Upon discovery of leakage from a Class 1, 2, or 3 pressure boundary component (pipe wall, valve body, pump casing, etc.), the licensee must declare the component inoperable. Evidence of leakage from the pressure boundary indicates the presence of a through-wall flaw. It may be possible to use visual methods to determine the exterior dimension(s) and orientation of a through-wall flaw in a leaking component. When the outside surface breaking dimension of a through-wall flaw is small, the length and extent of the flaw inside the component wall may be quite long and potentially outside the limits established by the Code. For these reasons the component is declared inoperable while methods such as ultrasonic examination are performed to characterize the actual geometry of the through-wall flaw. However, after declaring inoperability for leakage from Class 3 moderate-energy piping, the licensee may evaluate the structural integrity of the piping by fully characterizing the extent of the flaw using volumetric methods and evaluating the flaw using the criteria of paragraph C.3.a of Enclosure 1 to GL 90-05. If the flaw meets the criteria, the piping can subsequently be deemed operable but degraded until relief from the applicable Code requirement or requirements is obtained from the NRC. Alternatively, the licensee can evaluate the structural integrity of leaking Class 3 moderate-energy piping using the criteria of Code Case N–513, which is approved with limitations imposed by the NRC staff and incorporated by reference in 10 CFR 50.55(a)(b)(2)(xiii). The limitations imposed by the NRC staff are as follows:

a. Specific safety factors in paragraph 4.0 of Code Case N–513 must be satisfied, and

b. Code Case N–513 may not be applied to:
   (1) components other than pipe and tubing,
   (2) Leakage through a gasket,
   (3) threaded connections employing nonstructural seal welds for leakage prevention (through seal weld leakage is not a structural flaw, but thread integrity must be maintained), and
   (4) degraded socket welds.

Following the declaration of inoperability, the licensee may also decide to evaluate the structural integrity of leaking Class 2 or 3 moderate-energy piping using the criteria of Code Case N–513–1. The same limitations imposed by the NRC staff on Code Case N–513 apply to Code Case N–513–1. Code Case N–513–1 has been reviewed and found acceptable by the NRC. However, Code Case N–513–1 has not yet been incorporated into RG 1.147 or the Code of Federal Regulations for generic use. Therefore, until Code Case N–513–1 is approved for generic use in either RG 1.147 or 10 CFR 50.55a, the licensee must request relief and obtain NRC approval to use Code Case N–513–1.

If the piping meets the criteria of ASME Code Case N–513, continued temporary service of the degraded piping components is permitted. If the licensee decides to control the leakage by mechanical clamping means, the requirements of Code Case 523-2, •Mechanical Clamping Devices for Class 2 and 3 Piping Section XI, Division 1," may be followed, as referenced in 10 CFR 50.55a(b)(2)(xiii). This Code Case is to maintain the structural integrity of Class 2 and 3 piping which is 6 inches (nominal pipe size) and smaller and shall not be used on piping larger than 2 inches (nominal pipe size) when the nominal operating temperature or pressure exceeds 200°F or 275 psig. These and other applicable Code Cases which have been determined to be acceptable for licensee use without a request or authorization from the NRC are listed in RG 1.147. These Code Cases do not apply to Class 1 pressure boundary components.

The NRC has no specific guidance or generically approved alternatives for temporary repair of flaws (through-wall or non-through-wall) in Class 1, 2, or 3 high-energy system components, or for Class 2 or 3 moderate-energy system pressure boundary components other than piping. Therefore, all such flaws in these components must be repaired in accordance with Code requirements, or relief from Code requirements must be requested of and approval obtained from the NRC.

C.13 Structural Requirements

Structures may be required to be operable by the TSs, or they may be related support functions for SSCs in the TSs. Examples of structural degradation are concrete cracking and spalling, excessive deflection or deformation, water leakage, rebar corrosion, missing or bent anchor bolts, and degradation of door and penetration sealing. If a structure is degraded, the licensee should assess the structure's capability of performing its specified function. As long as the identified degradation does not result in exceeding acceptance limits specified in applicable design codes and standards referenced in the design basis documents, the affected structure is either operable or functional.

NRC inspectors, with possible headquarters support, should review licensees' evaluations of structural degradations to determine their technical adequacy and conformance to licensing and regulatory requirements.

END

NRC STAFF

EXHIBIT 20

combination of component type, material, environment, AERM, and AMP in LRA Table 2 with the GALL Report items. If there are no corresponding items in the GALL Report, the applicant leaves the column blank. In this way the applicant identified the AMR results in the LRA tables corresponding to the items in the GALL Report tables.

(8) Table 1 Item - The eighth column lists the corresponding summary item number from LRA Table 1. If the applicant identifies in each LRA Table 2 AMR results consistent with the GALL Report the Table 1 line item summary number should be listed in LRA Table 2. If there is no corresponding item in the GALL Report, column eight is left blank. In this manner, the information from the two tables can be correlated.

(9) Notes - The ninth column lists the corresponding notes used to identify how the information in each Table 2 aligns with the information in the GALL Report. The notes, identified by letters, were developed by an NEI work group and will be used in future LRAs. Any plant-specific notes identified by numbers provide additional information about the consistency of the line item with the GALL Report.

3.0.2 Staff's Review Process

The staff conducted three types of evaluations of the AMRs and AMPs:

(1) For items that the applicant stated were consistent with the GALL Report, the staff conducted either an audit or a technical review to determine such consistency.

(2) For items that the applicant stated were consistent with the GALL Report with exceptions, enhancements, or both, the staff conducted either an audit or a technical review of the item to determine such consistency. In addition, the staff conducted either an audit or a technical review of the applicant's technical justifications for the exceptions or the adequacy of the enhancements.

The SRP-LR states that an applicant may take one or more exceptions to specific GALL AMP elements; however, any deviation from or exception to the GALL AMP should be described and justified. Therefore, the staff considers exceptions as being portions of the GALL AMP that the applicant does not intend to implement.

In some cases, an applicant may choose an existing plant program that does not meet all the program elements defined in the GALL AMP. However, the applicant may make a commitment to augment the existing program to satisfy the GALL AMP prior to the period of extended operation. Therefore, the staff considers these augmentations or additions to be enhancements. Enhancements include, but are not limited to, activities needed to ensure consistency with the GALL Report recommendations. Enhancements may expand, but not reduce, the scope of an AMP.

(3) For other items, the staff conducted a technical review to verify conformance with 10 CFR 54.21(a)(3) requirements.

Staff audits and technical reviews of the applicant's AMPs and AMRs determine whether the aging effects on SCs can be adequately managed to maintain their intended function(s) consistent with the plant's current licensing basis (CLB) for the period of extended operation, as required by 10 CFR Part 54.

3.0.2.1 Review of AMPs

For AMPs for which the applicant claimed consistency with the GALL AMPs, the staff conducted either an audit or a technical review to verify the claim. For each AMP with one or more deviations, the staff evaluated each deviation to determine whether the deviation was acceptable and whether the modified AMP would adequately manage the aging effect(s) for which it was credited. For AMPs not evaluated in the GALL Report, the staff performed a full review to determine their adequacy. The staff evaluated the AMPs against the following 10 program elements defined in SRP-LR Appendix A.

(1) Scope of the Program - Scope of the program should include the specific SCs subject to an AMR for license renewal.

(2) Preventive Actions - Preventive actions should prevent or mitigate aging degradation.

(3) Parameters Monitored or Inspected - Parameters monitored or inspected should be linked to the degradation of the particular structure or component intended function(s).

(4) Detection of Aging Effects - Detection of aging effects should occur before there is a loss of structure or component intended function(s). This includes aspects such as method or technique (*i.e.*, visual, volumetric, surface inspection), frequency, sample size, data collection, and timing of new/one-time inspections to ensure timely detection of aging effects.

(5) Monitoring and Trending - Monitoring and trending should provide predictability of the extent of degradation, as well as timely corrective or mitigative actions.

(6) Acceptance Criteria - Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the structure or component intended function(s) are maintained under all CLB design conditions during the period of extended operation.

(7) Corrective Actions - Corrective actions, including root cause determination and prevention of recurrence, should be timely.

(8) Confirmation Process - Confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.

(9) Administrative Controls - Administrative controls should provide for a formal review and approval process.

(10) Operating Experience - Operating experience of the AMP, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support the conclusion that the effects of aging will be adequately managed so that the SC intended function(s) will be maintained during the period of extended operation.

Details of the staff's audit evaluation of program elements (1) through (6) are documented in SER Section 3.0.3.

The staff reviewed the applicant's quality assurance (QA) program and documented its evaluations in SER Section 3.0.4. The staff's evaluation of the QA program included assessment of the "corrective actions," "confirmation process," and "administrative controls" program elements.

The staff reviewed the information on the "operating experience" program element and documented its evaluation in SER Section 3.0.3.

3.0.2.2 Review of AMR Results

Each LRA Table 2 contains information concerning whether or not the AMRs identified by the applicant align with the GALL AMRs. For a given AMR in a Table 2, the staff reviewed the intended function, material, environment, AERM, and AMP combination for a particular system component type. Item numbers in column seven of the LRA, "GALL Report Volume 2 Item," correlates to an AMR combination as identified in the GALL Report. The staff also conducted onsite audits to verify these correlations. A blank in column seven indicates that the applicant was unable to identify an appropriate correlation in the GALL Report. The staff also conducted a technical review of combinations not consistent with the GALL Report. The next column, "Table 1 Item," refers to a number indicating the correlating row in Table 1.

3.0.2.3 UFSAR Supplement

Consistent with the SRP-LR, for the AMRs and AMPs that it reviewed, the staff also reviewed the UFSAR supplement, which summarizes the applicant's programs and activities for managing aging effects for the period of extended operation, as required by 10 CFR 54.21(d).

3.0.2.4 Documentation and Documents Reviewed

In its review, the staff used the LRA, LRA amendments, the SRP-LR, and the GALL Report.

During the onsite audit, the staff also examined the applicant's justifications to verify that the applicant's activities and programs will adequately manage the effects of aging on SCs. The staff also conducted detailed discussions and interviews with the applicant's license renewal project personnel and others with technical expertise relevant to aging management.

3.0.3 Aging Management Programs

SER Table 3.0.3-1 presents the AMPs credited by the applicant and described in LRA Appendix B. The table also indicates the SSCs that credit the AMPs and the GALL AMP with which the applicant claimed consistency and shows the section of this SER in which the staff's evaluation of the program is documented.

Table 3.0.3-1 PNPS Aging Management Programs

PNPS AMP (LRA Section)	GALL Report Comparison	GALL Report AMPs	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Existing AMPs				
Boraflex Monitoring Program (B.1.1)	Consistent	XI.M22	auxiliary systems	3.0.3.1.1

PNPS AMP (LRA Section)	GALL Report Comparison	GALL Report AMPs	LRA Systems or Structures That Credit the AMP	Staff's SER Section
BWR CRD Return Line Nozzle Program (B.1.3)	Consistent with exceptions	XI.M6	reactor vessel, internals, and reactor coolant system	3.0.3.2.2
BWR Feedwater Nozzle Program (B.1.4)	Consistent with exceptions	XI.M5	reactor vessel, internals, and reactor coolant system	3.0.3.2.3
BWR Penetrations Program (B.1.5)	Consistent with exceptions	XI.M8	reactor vessel, internals, and reactor coolant system	3.0.3.2.4
BWR Stress Corrosion Cracking Program (B.1.6)	Consistent with exception and enhancement	XI.M7	reactor vessel, internals, and reactor coolant system	3.0.3.2.5
BWR Vessel ID Attachment Welds Program (B.1.7)	Consistent with exception	XI.M4	reactor vessel, internals, and reactor coolant system	3.0.3.2.6
BWR Vessels Internals Program (B.1.8)	Consistent with exceptions and enhancement	XI.M9	reactor vessel, internals, and reactor coolant system	3.0.3.2.7
Containment Leak Rate Program (B.1.9)	Consistent	XI.S4	engineered safety features systems / structures and component supports	3.0.3.1.2
Diesel Fuel Monitoring Program (B.1.10)	Consistent with exceptions and enhancements	XI.M30	auxiliary systems	3.0.3.2.8
Environmental Qualification (EQ) of Electric Components Program (B.1.11)	Consistent	X.E1	electrical and instrumentation and controls	3.0.3.1.3
Fatigue Monitoring Program (B.1.12)	Consistent	X.M1	reactor vessel, internals, and reactor coolant system / engineered safety features systems / auxiliary systems / steam and power conversion systems / structures and component supports	3.0.3.2.9
Fire Protection Program (B.1.13.1)	Consistent with exceptions and enhancements	XI.M26	auxiliary systems / structures and component supports	3.0.3.2.10
Fire Water System Program (B.1.13.2)	Consistent with exception and enhancements	XI.M27	auxiliary systems	3.0.3.2.11

PNPS AMP (LRA Section)	GALL Report Comparison	GALL Report AMPs	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Flow-Accelerated Corrosion Program (B.1.14)	Consistent	XI.M17	reactor vessel, internals, and reactor coolant system / auxiliary systems / steam and power conversion systems	3.0.3.1.4
Containment Inservice Inspection Program (B.1.16.1)	Plant-specific		structures and component supports	3.0.3.3.2
Inservice Inspection Program (B.1.16.2)	Plant-specific		reactor vessel, internals, and reactor coolant system / structures and component supports	3.0.3.3.3
Instrument Air Quality Program (B.1.17)	Plant-specific		engineered safety features systems / auxiliary systems	3.0.3.3.4
Oil Analysis Program (B.1.22)	Consistent with exception and enhancements	XI.M39	engineered safety features systems / auxiliary systems	3.0.3.2.13
Periodic Surveillance and Preventive Maintenance Program (B.1.24)	Plant-specific		engineered safety features systems / auxiliary systems / steam and power conversion systems / structures and component supports	3.0.3.3.5
Reactor Head Closure Studs Program (B.1.25)	Consistent with exception	XI.M3	reactor vessel, internals, and reactor coolant system	3.0.3.2.14
Reactor Vessel Surveillance Program (B.1.26)	Consistent with enhancement	XI.M31	reactor vessel, internals, and reactor coolant system	3.0.3.2.15
Service Water Integrity Program (B.1.28)	Consistent with exceptions	XI.M20	auxiliary systems	3.0.3.2.16
Masonry Wall Program (B.1.29.1)	Consistent	XI.S5	structures and component supports	3.0.3.1.10
Structures Monitoring Program (B.1.29.2)	Consistent with enhancements	XI.S6	structures and component supports	3.0.3.2.17
Water Control Structures Monitoring Program (B.1.29.3)	Consistent with enhancement	XI.S7	structures and component supports	3.0.3.2.18
System Walkdown Program (B.1.30)	Consistent	XI.M36	reactor vessel, internals, and reactor coolant system / engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.1.11

PNPS AMP (LRA Section)	GALL Report Comparison	GALL Report AMPs	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Water Chemistry Control - Auxiliary Systems Program (B.1.32.1)	Plant-specific		auxiliary systems	3.0.3.3.6
Water Chemistry Control - BWR Program (B.1.32.2)	Consistent	XI.M2	reactor vessel, internals, and reactor coolant system / engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.1.13
Water Chemistry Control - Closed Cooling Water Program (B.1.32.3)	Consistent with exception	XI.M21	reactor vessel, internals, and reactor coolant system / engineered safety features systems / auxiliary systems	3.0.3.2.19
New AMPs				
Buried Piping and Tanks Inspection Program (B.1.2)	Consistent with exception	XI.M34	engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.2.1
Heat Exchanger Monitoring Program (B.1.15)	Plant-specific.		engineered safety features systems / auxiliary systems	3.0.3.3.1
Metal-Enclosed Bus Inspection Program (B.1.18)	Consistent with exceptions	XI.E4	electrical and instrumentation and controls	3.0.3.2.12
Non-EQ Inaccessible Medium-Voltage Cable Program (B.1.19)	Consistent	XI.E3	electrical and instrumentation and controls	3.0.3.1.5
Non-EQ Instrumentation Circuits Test Review Program (B.1.20)	Consistent	XI.E2	electrical and instrumentation and controls	3.0.3.1.6
Non-EQ Insulated Cables and Connections Program (B.1.21)	Consistent	XI.E1	electrical and instrumentation and controls	3.0.3.1.7
One-Time Inspection Program (B.1.23)	Consistent	XI.M32 XI.M35	reactor vessel, internals, and reactor coolant system / engineered safety features systems / auxiliary systems	3.0.3.1.8
Selective Leaching Program (B.1.27)	Consistent	XI.M33	engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.1.9

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
ENTERGY NUCLEAR OPERATIONS, INC.	)	Docket No. 50-293-LR
	)	
(Pilgrim Nuclear Power Station)	)	ASLBP No. 06-848-02-LR
	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of “NRC STAFF INITIAL STATEMENT OF POSITION ON PILGRIM WATCH CONTENTION 1”, “NRC STAFF TESTIMONY OF TERENCE L. CHAN AND ANDREA T. KEIM CONCERNING PILGRIM WATCH CONTENTION 1”, “NRC STAFF TESTIMONY OF DR. JAMES A. DAVIS REGARDING PILGRIM WATCH CONTENTION 1”, CERTIFICATIONS of Terence L. Chan, Andrea T. Keim and Dr. James A. Davis and Exhibits 1 – 20 in the above-captioned proceeding have been served on the following by electronic mail and by deposit in the U.S. Nuclear Regulatory Commission’s internal mail system as indicated by a single asterisk(*), or by electronic mail and by deposit in the U.S. Mail System, as indicated by a double asterisk (**) this 29th day of January, 2008.

Administrative Judge*
Richard F. Cole
Atomic Safety and Licensing Board Panel
Mail Stop: T-3F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
E-mail: rfc1@nrc.gov

Administrative Judge*
Paul B. Abramson
Atomic Safety and Licensing Board Panel
Mail Stop: T-3F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
E-mail: pba@nrc.gov

Administrative Judge*
Ann Marshall Young, Chair
Atomic Safety and Licensing Board Panel
Mail Stop: T-3F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
E-mail: amy@nrc.gov

Office of Commission Appellate *
Adjudication
Mail Stop: O-16G4
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
E-mail: OCAAMail@nrc.gov

Sheila Slocum Hollis**
Duane Morris LLP
1667 K Street, NW, Suite 700
Washington, DC 20006
E-mail: sshollis@duanemorris.com

Office of the Secretary*
Attn: Rulemaking and Adjudications Staff
Mail Stop: O-16G4
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
E-mail: hearingdocket@nrc.gov

Atomic Safety and Licensing Board*
Mail Stop: T-3F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Terence A. Burke, Esq.**
Entergy Nuclear
1340 Echelon Parkway
Mail Stop: M-ECH-62
Jackson, MS 39213

Mary Lampert**
148 Washington Street
Duxbury, MA 02332
E- mail: lampert@adelphia.net

David R. Lewis, Esq.**
Paul A. Gaukler, Esq.
Pillsbury, Winthrop, Shaw, Pittman, LLP
2300 N Street, NW
Washington, DC 20037-1137
E-mail: david.lewis@pillsburylaw.com
paul.gaukler@pillsburylaw.com

Chief Kevin M. Nord**
Fire Chief & Director Duxbury Emergency
Management Agency
668 Tremont Street
Duxbury, MA 02332
E-mail: nord@town.duxbury.ma.us
Fax: 781-934-6530

Town Manager**
Town of Plymouth
11 Lincoln St.
Plymouth, MA 02360
E-mail: msylvia@townhall.plymouth.ma.us

/RA/

Kimberly A. Sexton
Counsel for the NRC Staff