RAS J-69

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 describ

Division of License Renewal.

A2. Since Novemb

team member for license rene

Renewal, I was the lead rese

Branch of the Office Nuclear I

Chemical Engineering Branch

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NRC.

Q3. Please describ

U.S. NUCLEAR REGULATORY COMMISSION
In the Matter of Entergy (Pilgrim Nuclear Power Station)
Docket No. 50-293-LR Official Exhibit No. 39
OFFERED by: Applicant/Licensee Intervenor
NRC Staff Other: NRC Staff Exh. 1
IDENTIFIED on 4-10-08 Witness/Panel
Action Taken: ADMITTED REJECTED WITHDRAWN
Reporter/Clerk Thibault

DOCKETED
USNRC

April 15, 2008 (10:00am)

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

Temp = SECY-027

DS03

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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.

James A. Davis, Ph.D
Statement of Professional Qualifications

CURRENT POSITION:

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

EDUCATION:

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

SUMMARY:

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

EXPERIENCE:

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

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:

1. J. A. Davis and R. W. Staehle, "Initiation of Stress Corrosion Cracks in Iron-Chromium-Nickel Alloys: an Electron Microscopy Study," Presented at the Research in Progress Symposium, Corrosion/69, March, 1969, Houston, Texas

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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.