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DOCKETED
USNRC

June 3, 2008 (8:00am)

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

June 2, 2008

Office of the Secretary
Attn: Rulemaking and Adjudications Staff
Mail Stop O-16C1
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Re: In the Matter of Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Vermont Yankee Nuclear Power Station), Docket No. 50-271-LR, ASLBP No. 06-849-03-LR
Filing Discussing A Proprietary Document

Dear Sir or Madam:

Please find enclosed for filing in the above-stated matter New England Coalition, Inc.'s Rebuttal Statement of Position, Testimony and Exhibits. One document that Entergy has designated proprietary is discussed in the rebuttal testimony of Dr. Joram Hopenfeld, Exhibit NEC-JH_63.

This document is: Letter to James Fitzpatrick from EPRI (February 28, 2000). It is a letter to an Entergy staff person at the Vermont Yankee (VY) plant, stating EPRI's evaluation of the VY FAC program, and recommending certain changes to that program.

Pursuant to the Protective Order governing this proceeding, an unredacted version of this filing will be served only on the Board, the NRC's Office of the Secretary, Entergy's Counsel, and the following persons who have signed the Protective Agreement: Sarah Hoffman and Anthony Roisman. A redacted version of this filling will be served on all other parties.

Thank you for your attention to this matter.

Sincerely,

Karen Tyler

Karen Tyler
SHEMS DUNKIEL KASSEL & SAUNDERS PLLC

Cc: attached service list

TEMPLATE = SECY-055

DS-03

NEW ENGLAND COALITION, INC.'S REBUTTAL EXHIBIT LIST

Exhibit Number	Name of Exhibit
NEC-JH_63	Prefiled Rebuttal Testimony of Joram Hopenfeld
NEC-JH_64	Electric Power Research Institute ("EPRI"), "Materials Reliability Program: Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application (MRP-47, Revision 1)" (September, 2005).
NEC-JH_65	EPRI, "R&D Status Report: Nuclear Power Division," *EPRI Journal* (January/February 1983): 52-54.
NEC-JH_66	Wire, Gary L. and William J. Mills, "Fatigue Crack Propagation Rates for Notched 304 Stainless Steel Specimens in Elevated Temperature Water," *Journal of Pressure Vessel Technology* 126 (August 2004): 318-326.
NEC-JH_67	US NRC Docket Numbers 50-247-LR and 50-286-LR, "New York State's Supplemental Citation in Support of Admission of Contention 26A" (May 22, 2008).
NEC-JH_68	Entergy, "Condition Report: Steam Dryer Inspection Indications," CR-VTY-2007-02133 (May 28, 2007).
NEC-JH_69	Simonen, Fredric A. and Stephen R. Gosselin, "Life Prediction and Monitoring of Nuclear Power Plant Components for Service-Related Degradation," *Journal of Pressure Vessel Technology* 123 (February 2001): 58-64.
NEC-JH_70	Tennessee Valley Authority, "Memorandum: Sequoyah Nuclear Plan Units 1 and 2 – Preliminary Report on the Condensate-Feedwater Piping Inspection – Suspected Erosion-Corrosion Areas" (January 27, 1987).
NEC-JH_71	Bignold, G.J. et al, "Paper 1," *Water Chemistry II, BNES* (1980): 5-18.
NEC-JH_72	Woolsey, I.S. et al, "Paper 96: The Infulence of Oxygen and Hydrazine on the Erosion-Corrosion Behaviour and Electrochemical Potentials of Carbon Steel under Boiler Feedwater Conditions," *Water Chemistry of Nuclear Reactor Systems 4* (1986): 337-44.
NEC-RH_04	Prefiled Rebuttal Testimony of Rudolf Hausler
NEC-RH_05	Hausler, Rudolf H., "Flow Assisted Corrosion (FAC) and Flow Induced Localized Corrosion: Comparison and Discussion" (June 2, 2008).

UNITED STATES
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:

Alex S. Karlin, Chairman
Dr. Richard E. Wardwell
Dr. William H. Reed

In the Matter of	)	
	)	
ENTERGY NUCLEAR VERMONT YANKEE, LLC	)	Docket No. 50-271-LR
and ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLBP No. 06-849-03-LR
	)	
(Vermont Yankee Nuclear Power Station)	)	

NEW ENGLAND COALITION, INC.
REBUTTAL STATEMENT OF POSITION

In accordance with 10 C.F.R. § 2.1207(a)(2) and the Atomic Safety and Licensing Board's ("Board") November 17, 2006 Order,[1] New England Coalition, Inc. ("NEC") hereby submits its Rebuttal Statement of Position ("Statement") on NEC's Contentions 2A and 2B (environmentally-assisted metal fatigue analysis), 3 (steam dryer), and 4 (flow-accelerated corrosion). In support of this Statement, NEC submits the attached rebuttal testimony of Dr. Joram Hopenfeld[2] and Dr. Rudolf Hausler,[3] and the Exhibits listed on the attached Rebuttal Exhibit List.

I. NEC CONTENTIONS 2A AND 2B

[1] Licensing Board Order (Initial Scheduling Order) (Nov. 17, 2006) at 10(D) (unpublished).

[2] Exhibit NEC-JH_63.

[3] Exhibit NEC-RH_04.

(Environmentally-Assisted Metal Fatigue Analysis)

The evidence contained in Entergy's and the NRC Staff's direct testimony and exhibits fails to prove the validity of Entergy's CUFen Reanalyses. Indeed, NRC Staff witness Dr. Chang has testified that the NRC Staff cannot determine the conservatism of Entergy's analysis, and must therefore rely on Entergy's proposed fatigue monitoring program to demonstrate its conservatism during the period of extended operation. *See,* Chang Rebuttal Testimony at A10. The Board should therefore decide Contentions 2A and 2B in NEC's favor. The Board should find that Entergy has failed to satisfy § 54.21(c)(1)(ii) by projecting its environmentally-assisted metal fatigue TLAA to the end of the period of extended operation, and therefore must now rely, pursuant to § 54.21(c)(1)(iii), on an aging management program to provide reasonable assurance of public health and safety. NEC should then be permitted to litigate its Contention 2, now held in abeyance, which addresses the sufficiency of Entergy's aging management plan for environmentally-assisted metal fatigue.

NEC's rebuttal evidence concerning Contentions 2A and 2B is contained in the prefiled rebuttal testimony of Dr. Joram Hopenfeld, Exhibit NEC-JH_63 at 2-19 and additional rebuttal Exhibits NEC-JH_64 – NEC-JH_67.

A. The NRC Staff Misconstrues the Requirements of 10 CFR § 54.21(c)(1).

The NRC Staff's ("the Staff") Initial Statement of Position misconstrues 10 CFR § 54.21(c)(1). By the Staff's construction of this rule, Entergy could resolve any of NEC's Contention 2A and 2B criticisms of the CUFen reanalyses through a commitment to continued "refinement" of these analyses after the close of the ASLB proceeding. The Staff's position is inconsistent with standard rules of statutory and regulatory construction, as well as with this Board's treatment of NEC's Contention 2, 2A and 2B in this proceeding to date. Most importantly, it would defeat the ability of any license renewal intervenor to litigate an applicant's Time Limited Aging Analysis ("TLAA") methodology.

Section 54.21(c)(1) allows a license renewal applicant three options to address an aging–related health and safety issue that it has evaluated under its current license through analysis that involves time-limited assumptions. It reads as follows:

> (c) An evaluation of time-limited aging analyses.
>
> (1) A list of time-limited aging analyses, as defined in § 54.3, must be provided. The applicant shall demonstrate that –
>
> > (i) The analyses remain valid for the period of extended operation;
> > (ii) The analyses have been projected to the end of the period of extended operation; or
> > (iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

10 CFR § 54.21(c). Under § 54.21(c)(1)(i), the applicant may demonstrate that the analysis performed under its current license is valid for the period of extended operation. If the applicant is unable to satisfy § 54.21(c)(1)(i), it may project the analysis to the end of the period of extended operation under § 54.21(c)(1)(ii). Finally, if the applicant is unable to demonstrate reasonable assurance of public health and safety through a TLAA analysis under § 54.21(c)(i) or § 54.21(c)(ii), it must then develop an aging management plan under § 54.21(c)(1)(iii).

Entergy's CUFen reanalyses are properly subject to 10 CFR § 54.21(c)(1)(ii) – Entergy has performed these reanalyses in an attempt to demonstrate that its CUFen TLAA has been projected to the end of the period of extended operation. This was the

NRC Staff's view in August, 2007. Then, the Staff rejected Entergy's license renewal commitment to complete its CUFen reanalyses prior to entering the period of extended operation on grounds that "in order to meet the requirements of 10 CFR § 54.21(c)(1), an applicant for license renewal must demonstrate in the LRA that the evaluation of the time-limited aging analyses (TLAA) has been completed." *See*, Exhibit NEC-JH_62 at Enclosure 2.

Now, however, the NRC Staff takes the position that Entergy's CUFen Reanalyses constitute a "corrective action" to "manage the effects of aging" that falls under 10 CFR 54.21(c)(1)(iii). The Staff has thus reversed its view of when Entergy must complete its CUFen reanalyses. It is now the Staff's opinion that Entergy may perform the CUFen Reanalysis as part of its aging management program after its license renewal application is granted, possibly even during the period of extended operation. The Staff explains:

> If a licensee chooses to satisfy § 54.21(c)(1)(i) or (ii), the 'demonstration' must be in the LRA, and a commitment to perform analyses projecting 60-year CUFs prior to the period of extended operation is inconsistent with the regulatory language. However, if the licensee chooses to satisfy § 54.21(c)(1)(iii), the licensee must instead demonstrate that effects of aging *will* be adequately managed and a commitment to perform refined CUF analyses in the future as part of an aging management program is acceptable.

NRC Staff Initial Statement of Position at 11-12 (emphasis in original).

The Staff's interpretation of § 54.21(c)(1) is inconsistent with its plain language, and with standard rules of construction. Part 54.21(c)(1)(iii) is properly interpreted as a requirement to manage aging in the event the TLAA cannot be projected to the end of the license renewal period. In other words, an applicant may avoid the obligation to develop an aging management plan under § 54.21(c)(1)(iii) if it satisfies § 54.21(c)(1)(i) or

54.21(c)(1)(ii) by including a demonstration that the TLAA is either valid or can be projected for the period of extended operation in the LRA. Under the NRC Staff's construction, parts 54.21(c)(1)(i) and 54.21(c)(1)(ii) collapse into part 54.21(c)(1)(iii): that is, the TLAA demonstration becomes a component of the aging management plan, instead of a means to avoid the obligation to develop an aging management plan. The Staff's construction is therefore invalid. *Cf.* Dunn v. CFTC, 519 U.S. 465, 472, 473, 117 S.Ct. 913, 137 L.Ed.2d 93 (1997) (rejecting an interpretation of a statute that would have left part of it "without any significant effect at all," because "legislative enactments should not be construed to render their provisions mere surplusage.").

The Staff's interpretation is also inconsistent with the Board's interpretation of NEC's Contentions 2, 2A and 2B in this proceeding to date, which treats Entergy's CUFen reanalyses as distinct from its metal fatigue aging management plan, and as an alternative to a management plan. The Board ruled that NEC's Contention 2 addresses the sufficiency of the metal fatigue management program. It held Contention 2 in abeyance, to be litigated only if NEC prevails on Contentions 2A and 2B, and Entergy then reverts to reliance on fatigue management. The Board's Order of November 7, 2007 reads in relevant part as follows:

> When this litigation began, Entergy's application showed certain CUFs to be greater than unity, and Entergy indicated that it would manage such metal fatigue over the 20-year renewal period. NEC's original Contention 2 challenged the adequacy of Entergy's demonstration of its metal fatigue management program. Now Entergy says it has recalculated the CUFs to show that they are all less than 1, thus eliminating the need to manage metal fatigue over the renewal period. NEC Contention 2A challenges Entergy's recalculation of the CUFs. If NEC Contention 2 is successful and Entergy's revised CUF analyses are not shown to be sufficient, then Entergy might return to relying on a fatigue management program as a way of satisfying the Part 54 regulations.

> Thus, we conclude that NEC Contention 2A will be litigated now, and NEC Contention 2 will be held in abeyance. The proviso is that the parties are not to litigate Contention 2 unless and until Entergy returns to reliance on a metal fatigue management program (as would likely happen if NEC prevails on NEC Contention 2A).

Memorandum and Order (Ruling on NEC Motions to File and Admit New Contention), November 7, 2007 at 12.

Finally, the Staff's position that Entergy's environmentally-assisted metal fatigue TLAA analysis should be treated as a component of its metal fatigue aging management plan under § 54.21(c)(1)(iii) has significant consequences for the rights of NEC and other license renewal intervenors to obtain information about and contest the validity of TLAAs. Per the Staff's view, the applicant may comply with § 54.21 through a commitment to perform the TLAA analysis after the application is granted, an approach that will obviously frustrate public scrutiny of the TLAA methodology.

These consequences are already playing out in the ASLB proceeding concerning Entergy's license renewal application for the Indian Point plant, in which both the State of New York and Riverkeeper, Inc. have petitioned for admission of a contention similar to NEC's Contention 2. Entergy has taken the positions that it should not be required to provide <u>any</u> information about its CUFen analyses for the NUREG/CR-6260 locations until after the close of the ASLB proceeding, and the Staff should accept a commitment to perform CUFen analyses as part of the Fatigue Monitoring Program per 10 CFR § 54.21(c)(1)(iii). *See,* Exhibit NEC-JH-67 at Attachment 1, Enclosure 2, (see discussion of D-RAI 4.3.1.8-1 and D-RAI 4.3.1.8-2). The NRC Staff has apparently acquiesced in Entergy's effort to avoid public scrutiny of its CUFen methodology, and withdrew requests for this information. Id.

The Board should reject the Staff's interpretation of 10 CFR § 54.21(c)(1). It should find that Entergy's CUFen Reanalyses fall under § 54.21(c)(1)(ii), and must be completed as part of Entergy's License Renewal Application. The Board should further find that Entergy cannot satisfy § 54.21(c)(1) with a license renewal commitment to fix any problems in its CUFen Reanalyses, demonstrate the conservatism of those analyses, or finish those analyses after the close of the ASLB proceeding.

B. Entergy's Evidence Does Not Include Information Necessary to Validate its CUFen Reanalyses; Entergy Therefore Fails to Satisfy its Burden of Proof.

Dr. Hopenfeld testifies that Entergy has not provided to NEC or filed in the evidentiary record before the Board the following information necessary to validate its CUFen Reanalyses:

1. Drawings of the VY plant piping from which it would be possible to validate Entergy's assumptions of uniform heat transfer distribution, including orientation angles, weld locations and internal diameters, Hopenfeld Rebuttal at A18, Exhibit NEC-JH_03 at 8;

2. A complete description of the methods or models used to determine velocities and temperatures during transients, Hopenfeld Rebuttal at A19, Exhibit NEC-JH_03 at 9; and

3. Information regarding exactly how the number of plant transient cycles was determined for purposes of the 60-year CUF calculations, from which it would be possible to evaluate the conservatism of the cycle count, Hopenfeld Rebuttal at A21.

Regarding the first two issues, Entergy represents that some information was provided: 36 drawings, a copy of the Design Information Record, and some information regarding the calculation of flow velocity in response to Counsel's inquiry. Entergy Initial Statement of Position at 14. Dr. Hopenfeld testifies that the information Entergy provided is insufficient. Hopenfeld Rebuttal at A18 and A19.

Entergy further faults NEC for failing to request any additional information it considered necessary to a complete evaluation of the CUFen analyses in "discovery." Id. This argument of course ignores the fact that, to its tremendous disadvantage, NEC has no right to formal discovery in this Subpart L proceeding. *See,* 10 CFR § 1.1203, Hearing file; prohibition on discovery; *In the Matter of Entergy Nuclear Vermont Yankee, LLC, and Entergy Nuclear Operations, Inc. (Vermont Yankee Nuclear Power Station)*, 64 NRC 131, 202, ASLBP 06-849-03-LR, (September 22, 2006)("under the 'informal' adjudicatory procedures of Subpart L, discovery is prohibited except for certain mandatory disclosures.").

More importantly, Entergy's argument that NEC should have requested information in fictitious "discovery" misses the point. Entergy has the burden of proof regarding whether its CUFen reanalyses satisfy 10 CFR § 54.21(c)(1)(ii), and provide reasonable assurance of public health and safety. Entergy does not even attempt to explain why its record evidence concerning the VY pipe configuration and the methods or models it used to determine velocities and temperatures during transients is sufficient to validate its CUFen reanalyses. Entergy therefore fails to meet its burden.

With respect to the third issue above, the transient cycle count, Dr. Hopenfeld testifies that the explanation stated in Entergy's direct testimony of its means of determining the number of plant transients for purposes of its CUF calculations is inconsistent with information Entergy provided in its LRA and in the reports of the CUFen analyses produced to NEC. Hopenfeld Rebuttal at A21. Entergy's direct testimony on this subject is vague, and does not indicate that an allowance was made for the likely increase in plant transients resulting from the 20 percent power uprate or the fact that the number of plant transients is likely to increase as a plant ages. Id. Dr. Hopenfeld is unable to determine whether Entergy's transient cycle count is conservative. Id.

The NRC Staff's Initial Statement of Position misrepresents the testimony of NRC Staff witness Dr. Chang with respect to the transient cycle count. The Statement of Position represents that the Staff "disagrees with NEC's assertion that Entergy's assumptions about the number of transients in its analyses are not conservative," and states that "[t]he Staff's position is that Entergy's assumptions are appropriate." NRC Staff Initial Statement of Position at 18. In fact and to the contrary, Dr. Chang testifies that the staff, like Dr. Hopenfeld, "cannot determine the level of conservatism regarding the number of transient cycles at this time," and therefore relies on Entergy's Fatigue Monitoring Program to "ensure that the cycle projection is valid **<u>and that the fatigue analysis results are conservative</u>**." Chang Rebuttal at A10 (emphasis added).

Thus, per the testimony of NRC Staff witness Dr. Chang, Entergy has not provided information to the NRC, or filed evidence before the Board, from which it is possible to determine whether its CUFen analysis results are conservative. Again, Entergy has not satisfied its burden of proof, and the Board must decide Contentions 2A and 2B in NEC's favor.

C. <u>Calculation of the Fen Multiplier</u>

1. <u>The NRC Staff and Entergy are Incorrect that the ASME Code Does Not Require the Fen Correction.</u>

Both Entergy and the NRC Staff contend that the ASME Code does not require any accounting for the effects of coolant environment on component fatigue life. This is incorrect. The Code requires that **the code user must account** for conditions in which the environment is more aggressive than air. Rebuttal Testimony of Joram Hopenfeld at A5, *citing*, ASME Code, Appendix B at B-2131.

2. <u>NRC Staff guidance that sanctions use of the equations and procedure described in NUREG/CR-6583 and NUREG/CR-5704 to calculate Fen multipliers is not dispositive. The Staff must prove the validity of this guidance, but has not done so.</u>

In response to Dr. Hopenfeld's argument that Entergy used outdated statistical equations published in NUREG/CR-6583 and NUREG/CR-5704 to calculate Fen values, when it should have instead considered data much more recently published in NUREG/CR-6909 (February 2007), both the NRC Staff and Entergy cite NRC guidance stated in Section X.M1 of the GALL Report, NUREG-1801, Vol. 1, which sanctions use of the NUREG/CR-6583 and NUREG/CR-5704 equations to calculate Fen multipliers. Entergy and the Staff also note that Regulatory Guide 1.207 recommends reference to NUREG/CR-6909 only for fatigue analyses in new reactors.

These guidance documents are by no means dispositive of NEC's criticisms of Entergy's method of calculating Fen values. "Agency interpretations and policies are not 'carved in stone' but must rather be subject to re-evaluation of their wisdom on a continuing basis." *Kansas Gas and Electric Co. (Wolf Creek Generating Station, Unit 1)*, 49 NRC 441, 460 (1999), *citing*, *Chevron USA, Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 863-64 (1984)).

The GALL report and Regulatory Guide 1.207 do not contain legally binding regulatory requirements. The Summary and Introduction to NUREG-1801, Vol. 1 includes the following explanation of its legal status:

> Legally binding regulatory requirements are stated only in laws; NRC regulations; licenses, including technical specifications; or orders, not in NUREG series publications.
>
> * * *
>
> The GALL report is a technical basis document to the SRP-LR, which provides the Staff with Guidance in reviewing a license renewal application .... ***The Staff should also review information that is not addressed in the GALL report or is otherwise different from that in the GALL report.***

NUREG-1801, Vol. 1, Summary, Introduction, Application of the GALL Report (emphasis added). Likewise, the face page to Regulatory Guide 1.207 states the following: "Regulatory Guides are not substitutes for regulations, and compliance with them is not required." Regulatory Guide 1.207; *See also, In the Matter of International Uranium (USA) Corporation*, 51 NRC 9, 19 (2000) ("[NRC NUREGS, Regulatory Guides, and Guidance documents] are routine agency policy pronouncements that do not carry the binding effect of regulations. . . .").

NUREG-1801, Vol. 1 and Regulatory Guide 1.207 do not preclude this Board from considering the question at the heart of NEC's Contentions 2A and 2B: What is the most appropriate method of calculating the effects of the environment on fatigue?

> [NUREGs] do not rise to the level of regulatory requirements. Neither do they constitute the only means of meeting applicable regulatory requirements. . . . ***Generally speaking, . . . such guidance is treated simply as evidence of legitimate means for complying with regulatory requirements, and the staff is required to demonstrate the validity of its guidance if it is called into question during the course of litigation.***

In the Matter of Carolina Power & Light Company and North Carolina Eastern Municipal Power Agency (Shearon Harris Nuclear Power Plant), 23 NRC 294 (1986), *citing, Metropolitan Edison Co. (Three Mile Island Nuclear Station, Unit 1)*, 16 NRC 1290, 1298-99 (1982) (emphasis added); *See also, In the Matter of Connecticut Yankee*

Atomic Power Company (Haddam Neck Point), 54 NRC 177, 184 (2001), *citing, Long Island Lighting Co. (Shoreham Nuclear Power Station, Unit 1)*, 28 NRC 288, 290 (1988)("NUREGs and similar documents are akin to 'regulatory guides.' That is, they provide guidance for the Staff's review, but set neither minimum nor maximum regulatory requirements."); *In the Matter of Private Fuel Storage, LLC,* 57 NRC 69, 92 (2003)("[A]n intervenor, though not allowed to challenge duly promulgated Commission regulations in the hearing process. . . is free to take issue with . . . NRC Staff guidance and thinking . . . .").

The Staff is required in this proceeding to prove the current validity of its guidance concerning the calculation of Fen multipliers, but has produced little if any evidence of this. Entergy and the NRC Staff offer only one substantive reason[4] for use of the NUREG/CR-6583 and NUREG/CR-5704 equations over information contained in NUREG/CR-6909: both contend that the NUREG/CR-6909 "procedure" is less conservative and will generally produce lower Fen multipliers for operating reactors. *See,* Fair Rebuttal at A5 and A6, Stevens Rebuttal at A50. Dr. Hopenfeld explains that the overall NUREG/CR-6909 "procedure" could be considered less conservative because NUREG/CR-6909 contains new air fatigue curves that are less conservative that the current ASME Code fatigue curves. Hopenfeld Rebuttal at A6. He further testifies, however, that he has never recommended use of these new air fatigue curves. Until the current fatigue curves in the Code are officially modified, these curves must be considered the "best representation of fatigue life in air." Id.

[4] The Staff also offers a nonsubstantive reason: i.e., that it would be inconvenient to change its guidance while a number of license renewal applications are pending or anticipated.

Dr. Hopenfeld explains that the alleged greater conservatism of the NUREG/CR-6583 and NUREG/CR-5704 "procedure" is irrelevant to his main point about how Entergy should have used information contained in NUREG/CR-6909 in its CUFen analyses. Hopenfeld Rebuttal at A6, A7. As Dr. Hopenfeld has previously testified, NUREG/CR-6909 describes many factors known to affect fatigue life that are not accounted for in the ANL 1998 Equations contained in NUREG/CR-6583 and NUREG/CR-5704. Dr. Hopenfeld's rebuttal testimony provides a summary of these factors at A5, Table 1, and observes that Entergy's direct testimony addresses only one of them, surface finish. Hopenfeld Rebuttal at A5. This is the relevant information Entergy should have taken from NUREG/CR-6909. Hopenfeld Rebuttal at A7. Entergy and NRC staff witnesses fail to explain why this information contained in NUREG/CR-6909, published after the GALL report, should be ignored in the license renewal process.

Dr. Hopenfeld testifies that, given the current state of the technology, it simply is not possible to calculate Fen multipliers that are precision-adjusted to plant conditions, as Entergy purports to have done. Hopenfeld Rebuttal at A7. Given the many uncertainties in the calculation of Fen, he recommends use of bounding values contained in NUREG/CR-6909 – 12 for austenitic stainless steel and 17 for carbon and low alloy steel. Id.

3. <u>NEC's Rebuttal Evidence Concerning Calculation of Fen Multipliers</u>

NEC witness Dr. Joram Hopenfeld's rebuttal testimony addresses the following additional technical issues regarding the calculation the Fen multipliers raised by Entergy and the NRC Staff.

- Dr. Hopenfeld disagrees with NRC witness Dr. Chang that Fen values of 12 for austenitic stainless 17 for carbon and low alloy steel represent a "worst case scenario," or that application of these values is unreasonably conservative. Hopenfeld Rebuttal at A9.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Stevens that Fen=17 applies only to high oxygen and temperature environments that do not exist at VYNPS. Hopenfeld Rebuttal at A10.

- Dr. Hopenfeld does not agree with Entergy and NRC Staff witnesses that any lack of conservatism in Fen values calculated by the ANL 1998 Equations is counterbalanced by excess conservatism in the ASME Code design fatigue curves. He observes that there is no general agreement among researchers that the current Code is conservative. Hopenfeld Rebuttal at A12.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Fitzpatrick that Entergy properly accounted for surface roughness effects through use of ASME Code design fatigue curves that include a "safety factor" to account for these effects. Hopenfeld Rebuttal at A13.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Fitzpatrick that Entergy has demonstrated its use of bounding values for oxygen as an input to the ANL equations in all its CUFen analyses. Hopenfeld Rebuttal at A14. Mr. Fitzpatrick refers to steady state values as determined by a computer Code called BWRVIA that Entergy has neither described nor provided to NEC. Id. Mr. Fitzpatrick does not address the impact on Fen of oxygen concentrations that occur during transients at higher levels than at steady state. Id.

- Dr. Hopenfeld testifies that it was inappropriate for Entergy to exclude a correction factor for cracking in the cladding and base metal of the feedwater nozzles based on results of its 2007 inspection of these nozzles for cracks in the base metal. Hopenfeld Rebuttal at A15.

D. Calculation of 60-Year CUFs

NEC witness Dr. Joram Hopenfeld's rebuttal testimony addresses the following issues, in addition to the above-discussed potential lack of conservatism in projecting transient cycles, regarding the calculation the 60-year CUFs raised by Entergy and the NRC Staff.

- Dr. Hopenfeld disagrees that Entergy's CUFen analyses properly applied a heat transfer equation that applies only to a fully developed turbulent flow to the VYNPS nozzles. Specifically, he disagrees with Entergy witness Mr. Stevens that flow in the feedwater nozzle is fully developed because the upstream horizontal pipe is 48 inches long. Hopenfeld Rebuttal at A16. Dr. Hopenfeld further observes that Mr. Stevens did not explain why, in transients where the flow stops and heat transfer occurs by natural convection, a correction was not made for circumferential variation of the heat transfer both during single phase flow and during condensation. Id.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Stevens that it is unnecessary to correct a heat transfer equation used in the CUFen Reanalyses by the ratio of the viscosities evaluated at the bulk and wall temperatures during each transient because there are minimal differences in temperature between the pipe wall and the bulk of the fluid. Hopenfeld Rebuttal at A17. Mr. Stevens did not quantify actual temperature differences, which could only be determined from data on wall and bulk fluid temperature histories for sample transients. Id. Such information was not provided. Id.

- Dr. Hopenfeld disagrees that Entergy's use of the simplified Green's Function methodology in its Initial CUFen Reanalysis introduced only a small error. Hopenfeld Rebuttal at A20. Entergy has neither explained nor investigated the physical reasons for discrepancies between results obtained by the Green's Function methodology and the more exact methodology, classic NB-3200 analysis. Id. Results obtained by the Green's Function methodology therefore incorporate unquantified uncertainties. Id.

E. Error Analysis

NEC witness Dr. Joram Hopenfeld's rebuttal testimony addresses the following issues regarding the need for error analysis raised by Entergy and the NRC Staff.

- Dr. Hopenfeld disagrees with Entergy's witness that it was not necessary to perform an error analysis to validate its analytical techniques because the stress analysis is based on bounding values. Hopenfeld rebuttal at A23.

- Dr. Hopenfeld disagrees with NRC witness Dr. Chang that an error analysis was unnecessary because of conservatism built into the ASME Code and the ANL 1998 Equations. Hopenfeld Rebuttal at A24.

III. NEC CONTENTION 3 (Steam Dryer)

NEC's rebuttal evidence concerning Contention 3 is contained in the prefiled rebuttal testimony of Dr. Joram Hopenfeld, Exhibit NEC-JH_63 at 20-24, and additional rebuttal Exhibits NEC-JH_68 and NEC-JH_69.

A. The Issue Before the Board is Whether a Steam Dryer Aging Management Plan Uninformed by Knowledge of Stress Loads on the

Dryer for Comparison to Fatigue Limits is Adequate to Provide Reasonable Assurance of Public Safety.

The validity of the steam dryer stress load modeling Entergy conducted during implementation of the VY power uprate as a basis for Entergy's steam dryer aging management plan during the period of extended operations has not been litigated in this proceeding or otherwise established. The Board has ruled that the assessment of this modeling conducted during the EPU proceeding was not dispositive for purposes of life extension:

> Entergy's apparent assertion that the history of the steam dryer issue in the separate EPU proceeding should resolve the issue in this proceeding is . . . without foundation. As demonstrated by Entergy's own pleadings, steam dryer issues were addressed in the EPU proceeding primarily in regard to the power ascension toward EPU levels and the first few operating cycles thereafter.

In the Matter of Entergy Nuclear Vermont Yankee, LLC, and Entergy Nuclear Operations, Inc. (Vermont Yankee Nuclear Power Station), 64 NRC 131, 189 (September 22, 2006).

Moreover, Entergy represented in its Motion for Summary Disposition of NEC's Contention 3 that its steam dryer aging management program will consist exclusively of periodic visual inspection and monitoring of plant parameters as described in General Electric Service Information Letter 644 (GE-SIL-644), will not involve the use of any analytical tool to estimate stress loads on the steam dryer, and will not rely on the finite element modeling conducted prior to implementation of the extended power uprate (EPU) in 2006 for knowledge of steam dryer stress loads.

In partially granting Entergy's Motion for Summary Disposition, the Board accepted Entergy's representation that its steam dryer aging management plan would not rely on the pre-EPU steam dryer modeling. Memorandum and Order (Ruling on Motion for Summary Disposition of NEC Contention 3), September 11, 2007 at 10 ("Entergy's expert confirms that this program does not require the use of the CFD and ACM computer codes or the finite element modeling conducted during the EPU."). In doing so, the Board rejected NEC's argument that it should be permitted to litigate the validity of the EPU steam dryer modeling as the basis for aging management. NEC's pleading in opposition to Entergy's Motion for Summary Disposition stated the following regarding this issue:

> As stated in the attached Third Declaration of Dr. Joram Hopenfeld, Entergy's claim that its steam dryer aging management program will not involve any means of estimating and predicting stress loads on the dryer simply is not credible. Exhibit 1, Third Declaration of Dr. Joram Hopenfeld ("Hopenfeld Declaration 3") ¶ 6. A valid steam dryer aging management program must include some means of estimating and predicting stress loads on the steam dryer, and determining that peak loads will fall below ASME fatigue limits. Hopenfeld Declaration ¶ 5.
>
> Entergy represents that it did conduct this analysis as part of the Vermont Yankee EPU power ascension testing using the ACM and CFD models. Hoffman Declaration ¶¶ 11-13. Entergy now proposes sole reliance on visual inspection and plant parameter monitoring during the renewed license period. Such reliance must be based on Entergy's previous ACM/CFD-based predictions that stress loads on the dryer will not cause fatigue failures. Hopenfeld Declaration ¶ 7. NEC's concerns regarding the validity of the ACM and CFD models and the stress and fatigue analysis Entergy conducted using these models therefore remain current and relevant.

New England Coalition, Inc.'s Opposition to Entergy's Motion for Summary Disposition of NEC's Contention 3 (Steam Dryer) (May 9, 2007) at 4.

Both Entergy and the NRC Staff now contend that Entergy's steam dryer aging management program *does* in fact rely on the steam dryer modeling conducted during EPU implementation for knowledge of dryer stress loads. *See,* Entergy Initial Statement of

Position at 32 ("[T]he loadings on the dryer derive from plant geometries . . . that have not changed since the uprate was implemented, so there has been no change to the loadings on the dryer and the resulting stresses. Therefore, there is no reason to provide continued instrumentation to measure loadings or further analytical efforts."); NRC Staff Initial Statement of Position at 19 (The Staff's position is that stress analysis as a means of estimating and predicting stress loads during operations "is not necessary because the results of the EPU power ascension program demonstrated that the pressure loads during the EPU operations do not result in stress on the steam dryer that exceed ASME fatigue stress limits.").

In light of the above-discussed procedural history, and Entergy's prior representations, the Board must disregard these current contentions that the modeling of the dryer during the EPU power ascension program is a proper basis for aging management. This issue has not been determined, and the Board took it off the table in its decision of Entergy's Motion for Summary Disposition. The issue now properly before the Board is whether an aging management plan that consists solely of plant parameter monitoring, and partial visual inspection, uninformed by knowledge of dryer loading, can provide reasonable assurance of public safety.

B. Hopenfeld Rebuttal

Dr. Joram Hopenfeld provides the following rebuttal testimony regarding the above-stated issue properly before the Board.

- Dr. Hopenfeld testifies that the ability to estimate the probability of formation of loose parts requires knowledge of the cyclic loads on the dryer to ensure that the dryer is not subjected to cyclic stress that would exceed the endurance limit. Hopenfeld Rebuttal at A28.

- Dr. Hopenfeld observes that Mr. Hoffman and Mr. Lukens do not provide a single quantitative assessment in support of this position, discussed in A56-62 of their testimony, that the inspection programs at VY ensure that the dryer will not fail. Id.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Lukens that "operating experience after the EPU (exemplified by the data collected during the 2007 inspection and the subsequent year of monitoring of plant operating parameters) demonstrates that the stresses experienced by the dryer are insufficient to initiate and propagate fatigue cracks." Hopenfeld Rebuttal at A29.

- Dr. Hopenfeld provides a section of the Entergy Condition Report previously filed as Exhibit NEC-JH_59 that includes General Electric's statement that "continued [steam dryer crack] growth by fatigue cannot be ruled out." This section of the Condition Report was previously inadvertently excluded due to a clerical error. Hopenfeld Rebuttal at A29. Dr. Hopenfeld also disagrees with Entergy witness Mr. Lukens that the inspection photographs provided in Entergy's Condition Report, Exhibit NEC-JH59 at 2-8, show that the cracks are inactive. Metallographic examinations would be required to demonstrate this, not remote camera photos. Hopenfeld Rebuttal at A31.

- Dr. Hopenfeld observes that IGSCC cracks that now exist in the VY steam dryer can provide sites for corrosion attack which would in turn accelerate crack growth under cycling loading. The rate of crack propagation would depend on load intensities and duration. Id.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Hoffman that design basis loads ("DBA") cannot cause dryer failure. Hopenfeld Rebuttal at A32.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Hoffman that it is not necessary to estimate and predict dryer stresses because "[c]onfirmation that stresses on the VY steam dryer remain within fatigue limits is provided daily by the fact that the dryer has been able to withstand without damage the increased loads imparted on it during power ascension and for the two years of operation since EPU was implemented." Hopenfeld Rebuttal at A33. Vibration fatigue is a time-related phenomenon; the fact that the dryer has not failed to date is not at all an indication that it will not fail in the future. Id.

- Dr. Hopenfeld testifies that Entergy has not provided a quantitative estimate of the probability of crack detection, but should have done so, since the entire dryer is not accessible to visual inspection. Hopenfeld Rebuttal at A35.

IV. NEC CONTENTION 4
(Flow-Accelerated Corrosion)

NEC's rebuttal evidence concerning Contention 4 is contained in the prefiled rebuttal testimony of Dr. Joram Hopenfeld, Exhibit NEC-JH_63 at 24-41; additional rebuttal Exhibits NEC-JH_70– NEC-JH_72; the prefiled rebuttal testimony of Dr. Rudolf Hausler, Exhibit NEC-RH_04; and Dr. Hausler's report titled "Flow Assisted Corrosion (FAC) and Flow Induced Localized Corrosion: Comparison and Discussion," Exhibit NEC-RH_05.

Entergy witness Dr. Horowitz has testified that it is not necessary to recalibrate or "benchmark" the CHECWORKS model with plant inspection data following a twenty percent power uprate. Joint Declaration of Jeffrey S. Horowitz and James C. Fitzpatrick on NEC Contention 4 – Flow-Accelerated Corrosion at A33, 34. Rather, Dr. Horowitz contends that the only update to the CHECWORKS model that is necessary following a twenty percent power uprate is the input of new values for flow rate and temperature into the model. Horowitz at A33, 34. Dr. Horowitz bases these assertions on his view that "[flow-accelerated corrosion (FAC)] wear rates vary roughly with velocity and do not increase with velocity in [a] non-linear (exponential) manner. . . .", Horowitz at A49, and his beliefs that FAC is not fundamentally a local phenomena, and the CHECWORKS model can accurately predict any variations in FAC rates related to geometric features. Dr. Horowitz contends that the CHECWORKS model accounts for any localized variations in FAC associated with geometric features through the use of "'geometric factors' to relate the maximum degradation occurring in a component, such as an elbow, to the degradation predicted to occur in a straight pipe." Horowitz at A47, A48.

Dr. Hopenfeld and Dr. Hausler disagree with Dr. Horowitz that recalibration of the CHECWORKS model is unnecessary following substantial changes in flow velocity and changes in temperature, and respond regarding Dr. Horowitz's grounds for this opinion as follows.

- Dr. Hausler testifies that the linear relationship between FAC rates and fluid velocity transitions to an exponential one as the local turbulence becomes such that erosional features become manifest. Whether such transition actually occurs when flow velocity increases following a power uprate must be determined experimentally. Hausler Rebuttal at A5, Exhibit NEC-RH_05.

- Dr. Hopenfeld stresses that "FAC is fundamentally a local phenomenon due to variations of local turbulence in curved pipe, nozzles, tees, orifices, etc," and that corrosion rates can be expected to "vary with location depending on the intensity of the local turbulence." Hopenfeld Rebuttal at A42, A52, A53, A54 He also disagrees with Dr. Horowitz that the rate of FAC corresponds weakly with the velocity, and varies less than linearly with time, and disputes the relevance of the data Dr. Horowitz cites in support of his position. Hopenfeld Rebuttal at A41, A46, A53, A55.

- Dr. Hausler does not agree that the CHECWORKS model, or any model, can fully account for variations in the rate of FAC due to geometric features and discontinuities. Hausler Rebuttal at A6; Exhibit NEC-RH_05. Some things cannot be specified. For example, the internal residual weld bead from the root pass may be 1/8 inch high in one case, and ¼ inch high in another case. Id. The upstream and downstream turbulence surrounding the weld bead will be more severe in the latter case, and a power uprate may disproportionately affect the flow over the larger bead. Id.

- Dr. Hopenfeld observes that, while Dr. Horowitz denies the need to recalibrate CHECWORKS, he recognizes the need to increase the FAC inspection scope by 50% to account for the power uprate. Hopenfeld Rebuttal at A48. Entergy does not disclose what fraction of the total FAC susceptible area in the VY plant the proposed increased monitoring would represent, and its significance is therefore entirely unclear. Id.

Both Dr. Hopenfeld and Dr. Hausler take issue with Dr. Horowitz's definition of FAC as corrosion in proportion to the flow rate, Horowitz at A46, and observe that this definition excludes the more severe forms of localized corrosion – erosion-corrosion, impingement and cavitation. Hausler Rebuttal at A6; Exhibit NEC-RH_05; Hopenfeld Rebuttal at A45. Both Hopenfeld and Hausler observe that this definition of FAC is entirely arbitrary. Erosion-corrosion, impingement and cavitation are extensions of FAC as the local flow intensity due to turbulence increases. The transition from one to the others is continuous and difficult to identify. Id. If CHECWORKS is unable to predict these more severe forms of localized corrosion related to high flow rates, which can particularly occur after a power uprate, then this is a serious shortcoming of the model and its application. Id.

Dr. Hausler and Dr. Hopenfeld also address the following additional issues:

- Dr. Hausler observes that the accuracy of CHECWORKS has been said to be within +/- 50%, but this statement is based on an erroneous interpretation of the graphic representation of predicted vs. measured wear. Hausler Rebuttal at A6; Exhibit NEC-RH_05. Actually, the accuracy is within a factor of 2 – the measured wear rates range from twice the prediction to half the prediction. Id. A factor of two difference between measured and predicted corrosion [or corrosion rate] can be quite significant with respect to selecting a particular item (line) for inspection during a refueling outage. Id.

- Dr. Hopenfeld disagrees with Dr. Horowitz's evaluation of industry FAC experience, and his contention that this experience demonstrates the efficacy of CHECWORKS. Hopenfeld Rebuttal at A39, A40, A49, A52, A53. Dr. Hopenfeld specifically disagrees that, in assessing industry FAC experience, a distinction should be drawn between pipe failures due to leaks and failures due to ruptures. Hopenfeld Rebuttal at A44, A53.

- Dr. Hopenfeld faults Entergy for its failure to specify the total FAC-susceptible area that is inspected during a typical outage. Hopenfeld Rebuttal at A43.
- Dr. Hopenfeld disputes Dr. Horowitz's suggestion that the oxygen concentration at VY did not change in 2003. Hopenfeld Rebuttal at A51.

V. CONCLUSIONS

Extended operation of VYNPS as Entergy has proposed in its LRA will jeopardize public health and safety. The LRA should be denied unless the important issues addressed by NEC's Contentions 2A, 2B, 3 and 4 are resolved.

June 2, 2008 New England Coalition, Inc.

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:

Alex S. Karlin, Chairman
Dr. Richard E. Wardwell
Dr. William H. Reed

In the Matter of

ENTERGY NUCLEAR VERMONT YANKEE, LLC, and ENTERGY NUCLEAR OPERATIONS, INC.

(Vermont Yankee Nuclear Power Station)

Docket No. 50-271-LR

ASLBP No. 06-849-03-LR

June 20, 2006

PRE-FILED REBUTTAL TESTIMONY OF Dr. JORAM HOPENFELD REGARDING NEC CONTENTIONS 2A, 2B, 3 AND 4

Q1. Please state your name.

A1. My name is Joram Hopenfeld.

Q2. Have you previously provided testimony in this proceeding?

A2. Yes. I provided direct testimony in support of New England Coalition, Inc.'s (NEC) Initial Statement of Position, filed April 28, 2008.

Q3. Have you reviewed the initial statements of position, direct testimony and exhibits filed by Entergy and the NRC Staff?

A3. Yes. I have reviewed Entergy's Initial Statement of Position on New England Coalition Contentions (May 13, 2008) and all exhibits thereto, the Joint Declaration of James C. Fitzpatrick and Gary L. Stevens on NEC Contention 2A/2B – Environmentally-Assisted Fatigue (May 12, 2008), the Joint Declaration of John R. Hoffman and Larry D. Lukens on NEC

Contention 3 – Steam Dryer (May 12, 2008), and the Joint Declaration of Jeffrey S. Horowitz and James C. Fitzpatrick on NEC Contention 4 – Flow-Accelerated Corrosion (May 12, 2008). I have also reviewed the NRC Staff Initial Statement of Position on NEC Contentions 2A, 2B, 3, and 4 and all exhibits thereto, the Affidavit of John R. Fair Concerning NEC Contentions 2A & 2B (Metal Fatigue) (May 13, 2008), the Affidavit of Kenneth Chang Concerning NEC Contentions 2A & 2B (Metal Fatigue) (May 12, 2008), the Chang Correction Letter with Enclosures (May 22, 2008), the Affidavit of Kaihwa R. Hsu, Jonathan G. Rowley, and Thomas G. Scarborough Concerning NEC Contention 3 (Steam Dryer) (May 13, 2008), and the Affidavit of Kaihwa R. Hsu and Jonathan G. Rowley Concerning NEC Contention 4 (Flow-Accelerated Corrosion) (May 13, 2008).

Q4. Entergy contends that you have no experience or expertise relevant to the testimony you have provided concerning NEC's Contentions 2A, 2B, 3 and 4. How do you respond?

A4. I have a Ph.D in mechanical engineering, concentrating in Heat Transfer, Applied Electrochemistry, and Fluid Dynamics. I have 46 years of experience in the area of material/environment interaction (corrosion, erosion, fatigue) and related instrumentation. I have designed and conducted corrosion tests, I have reviewed and approved material fatigue-related issues for the FFTF and the CRBR reactors, and I have participated in the development of related codes and standards. I have participated in the evaluation of numerous material/environment related issues, including stress corrosion cracking in BWRs. I have managed experimental programs related to fatigue and corrosion in nuclear and fossil plants. I worked on PWR steam generator material-related issues for eight years at the NRC. I have published many papers in related areas in peer-reviewed scientific journals. I hold two patents relating to the detection of erosion/corrosion piping damage. I personally funded erosion-corrosion research studies at the University of Virginia.

To address the issues NEC raises in its Contentions 2A, 2B, 3 and 4 requires a broad knowledge of heat transfer, corrosion and material fatigue. I believe that I have the expertise necessary to provide the Board with a competent assessment of the fatigue and FAC issues relevant to the determination of the effects of the BWR environment on FAC and fatigue life. The FAC and fatigue issues that I am addressing are not unique to the BWR environment, but rather are common to many environments.

I. NEC CONTENTIONS 2A AND 2B (environmentally-assisted metal fatigue analyses)

A. Entergy's Calculation of Environmental Correction Factor, Fen

Q5. Does the fact that NRC guidance stated in Section X.M1 of the GALL Report sanctions use of the NUREG/CR-6583 and NUREG/CR-5704 equations to compute Fen multipliers demonstrate that this methodology satisfies ASME Code specifications?

A5. No. Section 111 of the ASME Code prescribes a set of curves for calculating fatigue life for different materials. These design curves, also known as S-N curves, are presented in terms of stress and the number of cycles to failure and are strictly based on laboratory tests in air. These tests incorporate correction factors for the effects of surface roughness, data scatter, and component size. *See,* Exhibit NEC-JH-26 at 3. These factors are not "safety margins," as Entergy witness Mr. Fitzpatrick suggests in his direct testimony at A8; they are correction factors. Exhibit NEC-JH-26 at 3. The Code requires that in situations where the environment is more aggressive than air **the owner must account** for such conditions. ASME Code, Appendix B at B-2131 (emphasis added). The LWR environment is known to reduce fatigue life significantly compared to air. Exhibits NEC-JH-26 at 3 and NEC-JH-03 at 1.

The Fen methodology described in NUREG/CR-6583 and NUREG/CR-5704 is a developing technology still unfinished. It is a work in progress; it contains many loose ends that allow the analyst to a large degree to select a desired outcome. This has not gone unnoticed by EPRI, which cautioned that "**the current state of the technology with respect to the Fen methodology is incomplete or lacking in detail and specificity.**" Exhibit NEC-JH_64 at 4-25 (emphasis added).

Entergy and the NRC Staff are wrong in arguing that Entergy must strictly follow the provisions of Section XM.1 of the GALL report and use the NUREG/CR-6583 and NUREG/CR-5704 methodology ("ANL 1998 Equations") to calculate Fen in spite of the fact that new information in NUREG/CR-6909, Exhibit NEC-JH_26, conclusively demonstrates that the ANL 1998 Equations only partially account for the effect of LWR environments.

NUREG/CR-6909 describes in detail the many factors known to affect fatigue life that are not included in <u>either</u> the ANL 1998 Equations or the ANL 2007 Equations included in NUREG/CR-6909. A summary of the most significant of these factors is contained in the following Table 1. In my opinion, to comply with the ASME Code, Entergy must account for these known effects. As further discussed below, I believe it should do so by using bounding Fen values contained in NUREG/CR-6909.

<u>Table 1- Uncertainties in the ANL 1998 and 2007 Fen equations</u>

No.	**Factor**	**NUREG/CR -6909 Page #**	**Addressed/ Not Addressed by Entergy in Reply to NEC**	**Comments**
1	Data scatter	13, 59	Not addressed	Included only in the ASME Code design fatigue curves (in air only)
2	Surface Finish	14 &34 &35	Addressed (JCF) A52	JCF, A 52, is wrong that the surface finish is accounted in the ASME Code

No.	Factor	NUREG/CR -6909 Page #	Addressed/ Not Addressed by Entergy in Reply to NEC	Comments
				design fatigue curves. The Code accounts only for surface **finish in air.** The Fen as calculated by the ANL equations does not account for the effects of roughness **in water** which may not be the same as in air.
3	Size,	62	Not addressed	Included in the ASME code design fatigue curves (in air only)
4	Flow Rate	33	Not addressed	Not included in the ASME Code design fatigue curves
5	Strain rate	12, 38-40, 57	Not addressed	Not included in the ASME Code design fatigue curves
6	Heat to Heat Variation	36	Not addressed	Not included in the ASME Code design fatigue curves
7	loading history, mean stress	62	Not addressed	These effects are also discussed by Dr. Chopra at the ACRS hearing of Dec. 6, 2006, Exhibit NEC-JH-27 at 22.
8	Cyclic strain hardening	13	Not addressed	Not included in the ASME Code design fatigue curves.
9	Temperature below 150 C	28	Not addressed	At the December 6, 2006 ACRS hearing, Dr. Chopra stated that a decrease by a factor of two on life is possible. Exhibit NEC-JH-27 at 25.
10	Oxygen below 250 C		Not addressed	During reactor startups and shut downs the oxygen concentration increases by more than an order of magnitude in comparison to normal operating conditions as shown by EPRI. Exhibit NEC-JH_65 at 53. Entergy calculations are based on concentrations during normal operating conditions, which at VY varied between 123 and 31 ppm depending on period of operation and reactor location. Exhibit NEC-JH_06 at A2. Allowing for data scatter in the above oxygen concentrations, an increase by a factor of four in oxygen would increase the Fen by a factor of 55

No.	Factor	NUREG/CR -6909 Page #	Addressed/ Not Addressed by Entergy in Reply to NEC	Comments
				in comparison to the steady state values.
11	Trace impurities in water	30-31	Not addressed	
12	Sulfide Morphology	13	Not addressed	At low strain rate, variation morphology could result in an order of magnitude variation on life.
13	Existing Surface cracks		Not addressed	Existing fatigue cracks in the cladding or base metal can provide sites for accelerated corrosion and thereby accelerate fatigue failure under cycling loads.

NRC witness Mr. Fair testifies at A5 that the NRC does not require license renewal applicants to use the results of NUREG/CR-6909, Exhibit NEC-JH_26, because those results were not completed when the GALL guidelines were issued. The fact that the 8-year-old Section XM.1 specifications are silent about most of the required adjustments to the Fen equations because the NUREG/CR-6909 data was not available when the GALL report was published does not excuse Entergy from properly accounting for environmental effects. Mr. Fair does not explain how a methodology that ignores the factors that are not included in the ANL 1998 Equations but discussed in NUREG/CR-6909 can be in agreement with the ASME Code.

The NRC's acceptance of Entergy's CUFen values is not proof that Entergy is in compliance with the ASME code. It is also not proof that Entergy complies with 10 CFR 54.21(C), which requires a **demonstration** that components will operate safely in the **reactor environment.**

Q6. Do you agree that the ANL 1998 Equations contained in NUREG/CR-6583 and NUREG/CR-5704 are more conservative and will generally yield higher Fen multipliers for currently operating plants than the ANL 2007 Equations contained in NUREG/CR-6909?

A6. No – the ANL 2007 Equations will yield higher Fen multipliers in some cases, and lower Fen multipliers in other cases. *See,* Exhibit NEC –JH_26 at 38. NRC witness Mr. Fair incorrectly told the ACRS that the ANL 1998 equations result in higher Fens than the ANL 2007 equations. *See,* Exhibit NEC-JH_28 at 97. In the light of such blatant distortion by the NRC staff, one cannot expect decision makers such as the ACRS to understand the degree of uncertainty in Entergy's methodology.

When both the Entergy and NRC Staff witnesses allege that the NUREG/CR-6583 and NUREG/CR-5704 "procedure" is more conservative (Fair A5 and A6, Stevens A50), I believe they are referring to the fact that NUREG/CR-6909 contains new air fatigue curves that are less conservative than the current ASME Code fatigue curves. I have never recommended use of these new air fatigue curves. Until the current fatigue curves in the Code are officially modified, these curves must be considered the "best representation of fatigue life in air" and must be adhered to.

Most importantly, and I want to make this very clear, Entergy's and the NRC's Staff's discussion of the alleged greater conservatism of the NUREG/CR-6583 and NUREG/CR-5704 equations and "procedure" are totally irrelevant to my main point about how Entergy should have used information contained in NUREG/CR-6909 in its CUFen analyses.

Q7. What is your main point regarding the significance of NUREG/CR-6909? What information contained in this document should Entergy have used in its CUFen Analyses?

A7. As I have discussed in A5, above, NUREG/CR-6909 describes in detail the many factors known to affect fatigue life that are not included in <u>either</u> the ANL 1998 Equations or the ANL 2007 Equations. These factors do not exist in the laboratory environment but are important and known to be present in the reactor environment. <u>This</u> is the relevant information Entergy should have taken from NUREG/CR-6909.

My main point is that, given the current state of the technology, it simply is not possible to calculate Fen multipliers that are precision-adjusted to plant conditions, as Entergy purports to have done. Given the many uncertainties in the calculation of Fen, I recommend use of bounding values contained in NUREG/CR-6909 — 12 for austenitic stainless steel and 17 for carbon and low alloy steel.

Q8. Please further explain why you used a Fen of 12 for austenitic stainless steel and a Fen of 17 for carbon and low alloy steel in the CUFen recalculation stated in your report, Exhibit NEC-JH_03 at 19-20.

A8. As discussed in NUREG/CR-6909, these values are based on a review of laboratory data from 41 sources. The reason for favoring the bounding numbers over the use of the ANL equations is that the bounding values factor in a much wider range of parameters than the ANL equations, such as fatigue loadings' data acquisition and material variability.

Q9. Do you agree with NRC witness Mr. Chang that Fen values of 12 for austenitic stainless 17 for carbon and low alloy steel represent a "worst case scenario," or that application of these values is unreasonably conservative?

A9. No. The factors 12 and 17 may in fact represent the best-case scenario after all the uncertainties outlined in Table 1 are considered. In addition, application of Fen values of 12 and 17 in the VY environment is not overly conservative because these values do not account for the presence of cracks in the cladding and base metal of the feedwater nozzles, or for high oxygen concentrations during transients.

I also note that if the ASME Code design fatigue curves are conservative as some believe, including ANL, any lack of conservatism in the above Fen values may be compensated by the ASME curves. If on the other hand the ASME Code curves are not conservative, as other researchers believe, *See,* Exhibit NEC-JH_26 at 71, then the Fen factors 12 and 17 will have to be adjusted upwards.

Q10. Do you agree with Entergy witness Mr. Stevens that Fen=17 applies only to high oxygen and temperature environments that do not exist at VYNPS, in part because the plant has operated using hydrogen water chemistry since 2003?

A10. No. I do not agree that the factor 17 is restricted to high temperature and high oxygen environments. This factor is specified in NUREG/CR-6909 at 3 as applicable to "certain reactor operating conditions." NUREG/CR-6909 does not indicate that the factor of 17 is restricted only to high oxygen and high temperatures. Mr. Stevens provided no reference for his assertion that Fen=17 applies only to high oxygen and temperature environments for carbon and low-alloy steels.

I do not agree that either Fen=12 for austenitic stainless or Fen=17 for carbon and low alloy steel would apply only in extreme environments. For example, my reference 3 to this testimony is a paper by Garry Wire and William Mills, reporting a factor of 12 for 304 stainless steel in 288 degrees C and 20ppb oxygen concentrations. Exhibit NEC-JH_66 at 318. This temperature is typical of BWR operations and the 20 ppb is considerably below the VY oxygen concentrations. It is definitely not an extreme environment as claimed by Entergy. Wire and Mills report that "[c]rack growth rates of 304 SS in water were about 12 times the air rate." Id. I did not research the literature to find the exact conditions that correspond to the factor 17. I believe that this factor was provided by ANL as a general bounding number.

Even if Fen=17 did apply only to high oxygen environments, I would not agree that this factor should not be used at VY due to the 2003 switch to Hydrogen water chemistry. First, because Entergy switched to Hydrogen chemistry relatively recently, calculations must still be conducted for the higher oxygen concentrations. Second, as discussed below, Entergy does not know what the actual oxygen concentration is during transients at the surface of a given component and therefore an adequately conservative analysis must assume that this concentration is high.

Q11. Entergy and the NRC Staff argue that NUREG/CR-6909 does not recommend use of the bounding Fen values you used in your CUFen recalculation. How do you respond?

A11. Dr. Chopra, author of NUREG/CR-6909, understands the limitations of the Fen methodology very well, but he can only describe the "state of the art." He is not in a position to recommend or not recommend use of bounding Fen values. It is up to the user to assess his specific conditions and make the appropriate corrections to the ANL equations. Entergy has not done so. It selected a procedure that would produce CUFens less than unity.

Q12. Do you agree that any lack of conservatism in Fen values calculated by the ANL 1998 Equations is counterbalanced by excess conservatism in the ASME Code design fatigue curves?

A12. No. The Fen issue must be kept separate from the ASME Code design fatigue curve issue. One is not justified to use an arbitrary number for the Fen because one believes that the Code is conservative. **There is no general agreement among researchers that the current Code is conservative.** Until the current fatigue curves in the Code are officially modified, these curves must be considered the "best representation of fatigue life in air" and must be adhered to.

Entergy's and the NRC's opinions regarding the ASME code are irrelevant. Entergy and the NRC should not be allowed to create their own rules concerning how to adjust the ASME code, which in essence is exactly what they are doing by using a non-conservative Fen in the hope that this will be compensated by a perceived conservatism in the existing ASME fatigue curves. If all the users of the ASME Code were to follow Entergy's example it would render the ASME Code useless.

Q13. Do you agree with Entergy witness Mr. Fitzpatrick that Entergy's CUFen analyses properly accounted for surface roughness effects through use of ASME Code design fatigue curves that include a "safety factor" to account for these effects?

A13. No. The ASME Code incorporates a factor of about four on surface finish to account for different fabrication processes (on the order of 0.5 mils). Surfaces exposed to the LWR environment are subject to corrosion, erosion and pitting, exhibiting a combination of smooth surfaces, ridges and holes of various sizes, making it difficult to compare such surfaces to machined surfaces. Until data show that the corroded surfaces and machined surfaces equally affect fatigue, possible differences cannot be ignored because surface holes and grooves may provide sites for accelerated corrosion attack; the corrosion reactions could then accelerate crack growth under cyclic loads. Mr. Fitzpatrick did not provide any support for his statement that the ASME Code design fatigue curves already incorporate the relevant surface roughness.

Mr Fitzpatrick is also wrong in representing at several points in his testimony that the ASME Code includes safety factors for environmental effects. As discussed in NUREG/CR-6909 at 3, surface finish, size and scatter are **adjustments, not safety margins**.

Q14. Do you agree with Entergy witness Mr. Fitzpatrick that Entergy used bounding values for oxygen as an input to the ANL equations in all its CUFen analyses?

A14. No. First, Mr. Fitzpatrick is referring to steady state value as determined by a computer code called BWRVIA that Entergy has neither described nor provided to NEC. Second, Mr. Fitzpatrick completely ignores the high oxygen concentrations that occur during transients. *See,* Exhibit NEC-JH_65 at 52-53. To the best of my knowledge, there is no technology that can predict the oxygen concentration at a given surface during reactor transients. Furthermore, no analysis has been presented to show how such temporary high oxygen concentrations affect the Fen. Mr. Fitzpatrick also stated that the BWRVIA has been calibrated in steam under unspecified conditions that he did not describe. Such calibration does not address the oxygen concentrations in water during transients.

Q15. Was it appropriate for Entergy's Fen calculations to exclude any correction for cracking in the cladding and base metal of the feedwater nozzles based on results of Entergy's 2007 inspection of these nozzles for cracks in the base metal?

A15. No. Entergy stated in RAI 4.3-H-02 that the feedwater nozzle cladding may contain cracks and that such cracks could grow into the base metal. NRC Staff Exhibit 1 at 4-26 – 4-27. Entergy's 2007 inspection report stated that "No relevant information was recorded". Exhibit 2-33 at 4. Without stating the probability of detecting cracks at the clad metal interface and defining "relevant," the inspection results are useless. Even if the clad cracks have not yet penetrated the base metal, the interface between the clad and the base metal is a site for crack initiation where corrosion products can accumulate. Such surface cracks when discovered in pressure systems are usually ground out to prevent fast crack growth under cycling loads. The ANL equations were not corrected for the presence of known surface cracks even if they did not yet penetrate the base metal.

B. Entergy's Calculation of 60-Year CUFs in Air

Q16. You have testified that Entergy's CUFen analyses improperly applied a heat transfer equation that applies only to a fully developed turbulent flow to the VYNPS nozzles where flow most likely is not fully developed. Entergy witness Mr. Stevens has testified (A 54) that flow in the feedwater nozzle is fully developed because the upstream horizontal pipe is 48 inches long. How do you respond?

A16. Both the local distribution and the absolute rate of the heat transfer to or from the walls of the pipes affect fatigue loading. The CUF results are very sensitive to the heat transfer coefficients. *See,* Exhibit NEC- JH_15.

Mr. Stevens is wrong in stating (A 54) that the flow in the feedwater nozzle is fully developed because the upstream horizontal pipe is 48 inches long. Since the inside diameter of the nozzle is 9.7 inches, the L/D is approximately 5, which is not sufficient to establish a fully developed flow. *See,* Exhibit NEC- JH_29. About 30 to 60 diameters, depending on the Reynold's number, are required to establish a fully developed flow through the nozzle. Mr. Stevens did not provide the straight section lengths upstream of the recirculation and spray nozzles. If that length is also on the order of 48 inches the flow in these nozzles will not be fully developed because the diameter of these nozzles is larger than the diameter of the feedwater nozzle. Because the flow in the nozzles is not fully developed, variation in the heat transfer coefficient both axially and circumferentially can be expected. Data on wall thinning in the upstream sections of the straight pipe where the flow is not fully developed is also required because it may affect the velocity distribution in the nozzle.

In transients where the flow stops and heat transfer occurs by natural convection, Mr. Stevens did not answer the question why a correction was not made for circumferential variation of the heat transfer both during single phase flow and during condensation. It appears that Mr.

Stevens does not understand the issue because he refers to axial variations and not variations in the vertical direction that is inherent in natural convection flows.

Mr. Stevens' statement that Equation (3) is "bounding" is meaningless without any further explanation.

Q17. You have testified that Entergy improperly failed to correct a heat transfer equation used in its CUFen Reanalyses by the ratio of the viscosities evaluated at the bulk and wall temperatures during each transient. Entergy witness Mr. Stevens states that this correction is unnecessary when there are minimal differences in temperature between the pipe wall and the bulk of the fluid. How do you respond?

A17. Mr. Stevens is correct that when there are minimal differences in temperature between the pipe wall and the bulk of the fluid, variations in viscosity can be neglected. However, Mr. Stevens did not quantify actual temperature differences. A difference of 100 degrees F would affect the heat transfer coefficient by about 4%. The actual effect can only be determined from data on wall and bulk fluid temperature histories for sample transients. Such information was not provided.

Q18. You have testified that Entergy's reports of its CUFen Reanalyses do not include, and Entergy did not produce to NEC, drawings of plant piping from which you could obtain information necessary to validate Entergy's assumption of uniform heat transfer distribution. Entergy notes that it supplied NEC with 36 drawings. How do you respond?

A18. Exhibit NEC-JH-25 is illustrative of the "piping diagrams" Entergy produced. It would be virtually impossible to extract information necessary to determine the flow conditions from such sketches – for instance, orientation angles, weld location and internal diameters as they exist today.

Q19. You have testified that Entergy's reports of its CUFen Reanalyses do not include, and Entergy did not produce to NEC, a complete description of the methods or models used to determine velocities and temperatures during transients. Entergy represents that

this information was conveyed to NEC through counsel on April 14, 2008. How do you respond?

A19. I do not agree that information sufficient to validate Entergy's analysis either appears in Entergy's reports of its analyses or was conveyed on April 14, 2008. To calculate flow velocity, Entergy advised on April 14, 2008 that I should take the flow rates (of unknown accuracy) and divide them by flow area. It failed to indicate how one does this when the flow is zero. At the January 2008 public meeting between Entergy and the NRC Staff, Entergy's Counsel specifically instructed Entergy representatives not to answer any of my questions regarding the above issues. NEC requested information about the methods that were used to calculate temperatures during the transients, but Entergy did not supply that information, contrary to what is claimed in Entergy's Initial Statement of Position at 36.

I believe that Entergy's strategy in this and other proceedings has been to withhold the information necessary to support a thorough assessment of its analyses by intervenors. Notably, Entergy has now taken the position in the ASLB proceeding concerning Entergy's License Renewal Application for the Indian Point plant that it is not required to provide <u>any</u> information about its CUFen analyses for the NUREG/CR-6260 locations until after the close of the ASLB proceeding. Exhibit NEC-JH_67 at Attachment 1, Enclosure 2, (see discussion of D-RAI 4.3.1.8-1 and D-RAI 4.3.1.8-2). The NRC Staff has apparently acquiesced in Entergy's effort to avoid public scrutiny of its CUFen methodology, and withdrew requests for this information. Id.

Q20. Entergy claims that its use of the simplified Green's Function method in its initial CUFen Reanalysis introduced only a small error. Do you agree?

A20. No. Unless the analyst can explain the physical reasons for discrepancies between results obtained by the Green's Function methodology and the more exact methodology, classic NB-

3200 analysis, the results of the Green's Function methodology will incorporate unquantified uncertainties. At the January 2008 meeting between Entergy and the NRC Staff, Entergy was not able to explain such differences, and Entergy witness Mr. Stevens has now testified at A58 that "[t]he reason for this difference was not specifically investigated."

After arguing for months that the analysis with Green's Function produces conservative results, i.e. large CUFen values, Entergy agreed to prove this by using the classical NB-3200 analysis without Green's Function. The demonstration showed that the CUFen was 0.3531, seemingly confirming that the use of Green's Function produces conservative results because this value is smaller than 0.6392 (the value Entergy calculated with the Green's Function). *See,* Exhibit NEC-JH_03 at 6. This result, however, was obtained by lowering the Fen to 3.97 instead of keeping it at the 10.05 level for a valid comparison. When the correct value of Fen was used, 10.05, Entergy obtained a CUFen of 0.8930, which is substantially greater than 0.6392 (obtained with the Green's Function). Thus the use of the Green's Function may generate non-conservative results. My report, Exhibit NEC-JH_03 at 6, includes a table of the four different CUFen values Entergy has calculated for the feedwater nozzle. It is interesting to note that Entergy does not explain why an internal Entergy audit did not discover that the analyst was using incorrect Fen numbers before the NRC audit discovered that this was the case.

Q21. Has Entergy fully explained how it determined the number of plant transients, or provided information from which you could conclude that Entergy assumed a conservative number of transient cycles?

A21. No. Entergy has provided inconsistent and vague information regarding how it determined the number of transient cycles, and has not indicated that it made any allowance for the likely increase in plant transients resulting from the 20 percent power uprate or the fact that the number of plant transients is likely to increase as a plant ages. NRC Staff witness Mr. Chang has testified at A10 that "the staff cannot determine the level of conservatism regarding the number of transient cycles at this time."

Based on the documentation provided to NEC, Entergy determined the number of transients, N, for the total 60-year reactor life by counting the number of transients that the plant has experienced up to a certain date, n, and adjusting this number proportionally i.e. N= n x 60/t, where t is the number of years as of the above date. This procedure is described in License Renewal Application Table 4.3-2, Note 2, and Exhibit NEC-JH_18 at 3-18, Table 3-10, Note 2. Both of these documents state that CUF results are based on "actual cycles to date and projected to 60 years." Table 4.3-2 defines the projection as a linear extrapolation.

Entergy witness Mr. Fitzpatrick has testified at A55 that the procedure described in the License Renewal Application and in Exhibit NEC-JH_18 actually was not followed; instead the following was done:

> VY projections for 60 years were made based on all available sources, including the numbers of cycles for 40 years in the VY reactor pressure vessel Design Specification, the numbers of cycles actually analyzed in the VY Design Stress Report, and the numbers of cycles experienced by VY after approximately 35 years of operation (July 2007).

The above method of determining the number of cycles appears to be different from what was described in Tables 3-10 and 4.3.2, which are referenced above. In any event, the above description is too vague to allow one to determine how the number of transients was actually calculated. Mr. Fitzpatrick did not provide a reference that would explain how the above procedure was implemented.

Q22. You used the CUF values Entergy originally provided in its License Renewal Application in the CUFen recalculation stated in your report, Exhibit NEC-JH_03 at 19-20. Why did you use these values?

A22. Due to the many uncertainties and errors in Entergy's calculation of plant-specific 60-year CUFs discussed in this rebuttal testimony and in my direct testimony and report, Exhibit NEC-JH_03, I used the more conservative design basis CUFs which were produced by Entergy in Table 4.3-3 of the LRA.

C. Error Analysis

Q23. Entergy contends that it was not necessary to perform an error analysis to validate its analytical techniques because the stress analysis is based on bounding values. How do you respond?

A23. Because the level of uncertainty in Entergy's analysis is very high and the amount of valid data is meager, properly identified assumptions and a competent assessment of their relative effects on the CUFens is paramount. Entergy considered such an approach unnecessary and apparently found it sufficient to label their assumptions "bounding." Without quantifying by how much the various parameters are "bounding," Entergy's statement is meaningless. It has already been demonstrated that the heat transfer coefficients and the Fen factors are not bounding the results conservatively.

Q24. NRC Staff witness Mr. Chang contends that an error analysis was unnecessary because of conservatism built into the ASME Code and the ANL 1998 Equations, which he claims "have been adjusted for uncertainties in life." How do you respond?

A24. As I have discussed in A12 of this testimony, there is no agreement among researchers that the ASME Code design fatigue curves are conservative. With respect to the ANL 1998 Equations, Mr. Chang does not explain how adjustments were made for the factors listed in the Table 1 included in A5 of this testimony. Ten years of data and research have been accumulated since the ANL 1998 Equations were published; Mr. Chang does not explain why the license renewal process should ignore this data.

Q25. You have stated that Entergy's CUFen Reanalyses should be reviewed by an independent third party. Why do you make this recommendation?

A25. In addition to the uncertainties in heat transfer coefficients, Green's Function and the number of transients used in the analysis, there are many other uncertainties that are not possible to assess. The results of the stress analysis largely depend on the judgment of the analyst because he alone decides where the maximum stress points are and how to link transient pairs. The changes that were made in the Fen, discussed in A20 of this testimony, which resulted in an erroneously low CUFen is an example of how the analyst can affect the results. In the absence of an independent review by an unbiased third party without financial ties to Entergy, Entergy's 60-year CUF calculations are of questionable validity.

D. References

Q26. Please list any references to this testimony that were not filed as Exhibits to your direct testimony.

A26.

1. Materials Reliability Program: Guidelines For Addressing Environmental Fatigue License Effects in License Renewal Applications, EPRI- MPR-47 Rev. 1, September 2005. Exhibit NEC-JH_64.

2. R&D Status Report, EPRI Journal, Jan/Feb 1983. Exhibit NEC-JH_65.

3. Gary L. Wire and William J. Mills, "Fatigue Crack Propagation Rates for Notched 304 Stainless Steel Specimen in Elevate Temperature," Journal of Vessel Pressure Technology. Exhibit NEC-JH_66.

4. New York State's Supplemental Citation In Support of Admission of Contention 26A, Docket Nos. 50-247-LR and 50-286-LR (May 22, 2008), and the attached NRC May 8, 2008 Summary of an April 3, 2008 Telephone Conference Between Entergy and NRC Staff. Exhibit NEC-JH_67.

Q27. Does this conclude your rebuttal testimony regarding NEC's Contentions 2A and 2B?

A27. Yes.

II. NEC CONTENTION 3

(steam dryer aging management program)

Q28. Please summarize your disagreement with Entergy regarding the validity of its steam dryer aging management program.

A28. My position regarding the steam dryer at VY is simple: I disagree with Entergy that an aging management plan that consists solely of plant parameter monitoring and partial visual inspection, uninformed by knowledge of dryer loading, complies with the General Design Criteria insofar as they require that protection must be provided against the dynamic effects of loss of coolant accidents ("LOCAs").

Entergy's strategy is based on monitoring moisture carryover, steam flow, water level and dome pressure and periodic visual inspections. Entergy witness Mr. Hoffman was asked in Q33 whether these activities "enable Entergy to determine whether a dryer crack is about to form?" He responded in A33 that they do not. Of course no one can predict the exact time for transition from crack initiation to crack propagation. The question that was asked of Mr. Hoffman is almost irrelevant. The questions that should have been asked are as follows: (a) are all of the above precautionary measures sufficient to ensure that the probability of the formation of loose parts under DBA loads will be very low?; and (b) is Entergy taking all practical measures to minimize the probability of such failures? As discussed in my report submitted to the ASLB on April 28, 2008, Exhibit NEC-JH_54, the answer to both of these questions is no.

Entergy's witnesses, Mr. Hoffman and Mr. Lukens, described in detail various procedures of steam dryer inspection and the operational experience with the dryer, but they either dismissed or did not address properly the above two issues. The ability to estimate the probability of formation of loose parts requires knowledge of the cyclic loads on the dryer to ensure that the dryer is not subjected to cyclic stress that would exceed the endurance limit. In A56-62 of their testimony, Mr Hoffman and Mr. Lukens discuss this key issue and state that the prediction of cyclic stresses on the dryer is not required because there are no specific regulatory requirements to do so, and the inspection programs at VY ensure that the dryer will not fail. Mr. Hoffman and Mr. Lukens did not provide even a single quantitative assessment in support of these opinions.

I agree that there is no regulatory requirement to estimate dryer stresses. However, the fact that dryers at other plants have failed following power uprates, the fact that this was a surprise to General Electric ("GE"), the fact that even small pressure fluctuations can give rise to stresses that exceed the endurance limit and the fact that the formation of loose parts can lead to major safety problems are all factors that must be considered even though there are no specific NRC requirements to calculate stresses on the dryer.

Q29. Entergy witness Mr. Lukens testified at A56 that "operating experience after the EPU (exemplified by the data collected during the 2007 inspection and the subsequent year of monitoring of plant operating parameters) demonstrates that the stresses experienced by the dryer are insufficient to initiate and propagate fatigue cracks." How do you respond?

A29. Mr. Lukens is wrong that the inspection data he mentions is a measure of cyclic stresses. The only way of determining stresses on the dryer is to actually measure them. Fatigue cracking is a time-dependent phenomenon; the fact that cracks have not developed after a short period of time proves nothing. General Electric ("GE"), which conducted both the RFO26 and the 2007 steam dryer inspections at VY, did not exclude the possibility of crack growth by fatigue. GE stated: "The dryer unit end plates are located in the dryer interior and are not subjected to any direct main steam line acoustic loading. However, **continued growth by fatigue cannot be ruled out.**" Exhibit NEC-JH_68 at "Evaluation of Steam Dryer Indications" attachment (emphasis added).

Q30. Mr. Lukens at A57 denied that GE made the statement that "continued growth by fatigue cannot be ruled out," and testified that the reference you cited for this statement, Exhibit NEC-JH_59, did not contain it. How do you respond?

A30. Mr. Lukens misread my statement, which referred to GE's observations following the RF026 inspection. Due to a clerical error, Exhibit NEC-JH_59 included only part of the GE report; the full GE report is now provided as an Exhibit to this testimony. *See,* Exhibit NEC-JH_68. In any event, Mr. Lukens is the engineer responsible for the inspection of the dryer at VY; he should have been of aware of GE's conclusions, which are very material to the results of the inspection.

Q31. Mr. Lukens testified at A58 that all IGSCC cracks identified in the VY steam dryer to date are inactive. How do you respond?

A31. In stating that the IGSCC cracks are not active, Mr. Lukens essentially dismissed the possibility of continued growth of cracks by fatigue. He apparently did not recognize that IGSCC can provide sites for corrosion attack which would in turn accelerate crack growth under cycling loading. The rate of crack propagation would depend on load intensities and duration. Moreover, I cannot agree with Mr. Lukens that the inspection photographs provided in Entergy's Condition Report, Exhibit NEC-JH_59 at 2-8, show that the cracks are inactive. Metallographic examinations would be required to demonstrate this, not remote camera photos.

Q32. Mr. Hoffman testifies at A59 that design basis loads ("DBA") cannot cause dryer failure. How do you respond?

A32. I disagree. If the dryer has been sufficiently weakened by cracks, there is no reason to believe that DBA loads could not fracture the dryer. Instead of making speculative statements, Mr. Hoffman should have provided calculations showing that even if some parts of the dryer had long and deep cracks, those parts would withstand DBA loads.

Q33. Mr. Hoffman testifies at A61 and A62 that it is not necessary to estimate and predict dryer stresses because "[c]onfirmation that stresses on the VY steam dryer remain within fatigue limits is provided daily by the fact that the dryer has been able to withstand without damage the increased loads imparted on it during power ascension and for the two years of operation since EPU was implemented." Do you agree?

A33. No, I do not agree that it is not necessary to estimate stresses because the dryer has thus far withstood the increase in steam velocities followed the uprate. Vibration fatigue is a time-related phenomenon; the fact that the dryer has not failed to date is not at all an indication that it will not fail in the future. Mr. Hoffman is speculating that the loads on the dryer cannot change. Even a small increase in steam velocity can bring vortex shedding frequency closer to the natural frequency of the dryer, thereby inducing resonance vibrations and increasing the loads on the dryer.

Q34. Mr. Hoffman testified at A63 that the analytical tools used to estimate stress loads on the steam dryer during the power ascension phase of EPU implementation demonstrated that loads on the dryer would be below the endurance limit. Do you agree?

A34. No. Mr. Hoffman stated at A63 that the analytical tools demonstrated that the loads on the dryer would be acceptable. The analytical tools were based on small-scale experiments, small-scale tests (ACM) and questionable scaling laws, as was pointed out by the ACRS. *See, Transcript of Proceedings, NRC Advisory Committee on Reactor Safeguards, 528th Meeting* (December 7, 2005) at 9, 12-14, 25, 29, 60.

Q35. Has Entergy provided information sufficient to demonstrate the validity of its steam dryer aging management program?

A35. No. Mr. Hoffman and Mr. Lukens at A21-A53 provided a very lengthy and detailed description of the inspection techniques and parameter monitoring at VY. Even though the entire dryer is not accessible to visual inspection, Mr. Hoffman and Mr. Lukens did not provide a quantitative estimate of the probability of crack detection, POD. They should have provided this information.

Q36. Do you have any further comments regarding NEC's Contention 3?

A36. Yes. Entergy provided an opinion that the dryer will not be the source of loose parts that could present a safety risk during normal operations and during design basis accidents. Entergy believes that the formation of cracks from flow-induced vibrations can be detected in time by periodic visual inspections and plant parameter monitoring; I do not share this opinion. Rather I am more inclined to agree with the researchers from the Pacific Northwest National Laboratory: **"Unlike the previously discussed mechanisms (corrosion) vibration fatigue does not lend itself to periodic in-service examinations (volumetric, surface, etc) as a means of managing this degradation mechanism."** The main reason for this is: **"Once a crack initiates failure quickly follows."** Fredric A. Simonen and Stephen R. Gosselin, "Life Prediction and Monitoring of Nuclear Power Plant Components for Service-Related Degradation" J. of Pressure Vessel Technology V. 123, Feb. 2001, P, 62., Exhibit NEC-JH_69 at 62.

Q37. Please list any references to this testimony that were not filed as Exhibits to your direct testimony.

A37.

1. Entergy Condition Report, CR-VTY-2007-02133, including all attachments. Exhibit NEC-JH_68.

2. Fredric A. Simonen and Stephen R. Gosselin, "Life Prediction and Monitoring of Nuclear Power Plant Components for Service-Related Degradation", J. of Pressure Vessel Technology V. 123, Feb. 2001. Exhibit NEC-JH_69.

Q37. Does this conclude your rebuttal testimony regarding NEC's Contention 3?

A37. Yes.

III. NEC CONTENTION 4

(flow-accelerated corrosion management plan)

Q38. In response to Entergy's Prefiled Testimony on NEC Contention 4, please summarize your view of Entergy's proposed Aging Management Program (AMP) for Flow Accelerated Corrosion at Vermont Yankee Nuclear Power Station

A38. The NEC position on Flow Accelerated Corrosion, FAC, is that Entergy does not have a reliable plan to monitor FAC and therefore the public has no assurance that susceptible reactor components will be repaired and replaced in time to prevent pipe rupture or major leaks. Such damage to piping must be prevented not only during normal plant operation but also during design basic accidents (DBAs) in accordance with 10 CFR 50.49 (b) (2). The LRA must include an adequate plan to monitor FAC pursuant to 10 CFR 54.21 (a) (3).

The reason Entergy's FAC plan as described in the LRA is inadequate is because it is based on EPRI guidelines NSAC-202 L, which largely rely on an unproven computer code called CHECWORKS to predict corrosion rates and therefore the scope of the inspection. I evaluated the NSAC/CHECWORKS methodology and provided the results to the ASLB on April 28, 2008. Exhibit NEC-JH_36. I concluded that 12-15 years would be required to benchmark CHECWORKS at VY at the uprate conditions and with a smaller inspection grid size. I also recommended a methodology that would more adequately inspect pipes for potential failures from FAC.

I pointed out that several factors contribute to the inability of the NSAC/ CHECWORKS methodology to prevent pipe ruptures from unpredicted wall thinning: (a) incorrect local inspection procedures, i.e selection of grid size, (b) unscientific sampling of components, (c) inability to reliably predict corrosion rates between inspections, (d) no online instrumentation to monitor the potential for corrosion, and (e) lack of independent assessment by competent experts.

Q39. In your opinion, does Entergy's prefiled testimony appropriately address the issues raised in your assessment of Entergy's aging management program for FAC?

A39. No. Rather than provide a reply to the NEC and describe scientifically why NEC and Entergy differ regarding the various uncertainties in predicting wall-thinning rates, Entergy produced several documents that stated that CHECWORKS is a reliable predictive tool.

For instance, Entergy submitted an EPRI document (E4-09), which is no more than a sales brochure; it provided the sale price of CHECWORKS and informed the reader that no plant that acquired CHECWORKS has experienced FAC failures in pipes larger than 2 inches. No comparison was made with the plants and components that were not included in the CHECWORKS program since it was introduced in 1987 and also no explanation was given as to why the pipe size was that significant. This brochure also did not tell the reader that FAC was defined in a manner that would exclude pipe failures from erosion/corrosion, droplet impingement and cavitations erosion.

Entergy's statement that no one was killed in plants that used CHECWORKS, and the fact that pipes larger than 2 inches did not rupture in such plants is certainly not a credible demonstration that the use of CHECWORKS would satisfy 10 CFR 50.49 (b) (2) and 10 CFR 54.21 (a) (3).

Q40: Entergy witness Dr. Horowitz testifies that unanticipated piping failures that have occurred despite the widespread use of CHECWORKS are not an indicator of the relative efficacy of CHECWORKS. Do you agree?

A40. No, I do not. CHECWORKS is a proprietary product of EPRI and Dr. Horowitz is EPRI's contractor; thus, it is understandable that Dr. Horowitz would zealously defend CHECWORKS. He fails, however, to credibly explain away CHECWORKS' failure to predict the hundreds of unanticipated FAC-related failures that occurred in PWRs and BWRs. Dr. Horowitz testified (A52) that the problem was not with CHECWORKS and its predecessor programs, but rather the unpredicted failures occurred because of (a) improper use of CHECWORKS, (b) exclusion of components from the program, (c) modeling errors, (d) improper inspection, (e) poor communication, and (f) failures from erosion rather than FAC (A46). The fact that many components were not included in the CHECWORKS programs and that Dr. Horowitz selected a very narrow definition of FAC, or that CHECWORKS is susceptible to improper use provides no assurance to the public that pipe failures from wall thinning will be prevented and people and property will not be at risk. Even if, for the sake of argument, CHECWORKS has the potential to predict wall thinning with extreme accuracy but, as Dr. Horowitz says, many components may be excluded from the program, and CHECWORKS is prone to user's errors, then CHECWORKS cannot be considered a reliable predictive FAC tool for purposes of assuring public health and safety. Dr Horowitz failed to state what percentage of the total susceptible area in a given plant is included in the CHECWORKS program during a typical outage.

Q41. Do you agree with Entergy's position regarding the effect of flow velocity on FAC?

A41. No, I do not. NEC's presentation of how FAC rates vary with flow velocity is significantly different from Entergy's. NEC's position is based on data from tests that were conducted by the Central Electricity Research Laboratories at Leatherhead. The data was discussed and presented on pages 4 and 20 of Exhibit NEC-JH_36, showing the dependence of measured corrosion rates on the mass transfer coefficient for carbon and mild steel. The dependence of the mass transfer coefficient on velocity was discussed in NEC-JH_36 at 4. Also, the relation between corrosion and material composition was discussed on pages 4 and 21. Copper was not included in this discussion since it is not a common piping material in nuclear plants.

According to Entergy's witness Dr. Horowitz, the data in CHECWORKS is based on references given in E-4-22 and E-4-23. The first paper presented data on the local variation of the mass transfer with velocity and the second paper presented data on the dependence of the corrosion rate of **copper with the velocity in flowing hydrofluoric acid**. These papers hardly support Entergy's position that the corrosion rate corresponds very weakly with the velocity and therefore the velocity change due to the power uprate is of no significance. Dr. Horowitz did not demonstrate that the mechanism of copper dissolution in acids is the same as the dissolution of iron in the LWR environment.

It is beyond NEC's scope to conduct an uncertainty study on the impact of the various assumptions that were incorporated in CHECWORKS.

As discussed in my assessment of Entergy's FAC program, Exhibit NEC-JH_36, the NRC has developed specific guidelines for how computer codes that are used for licensing bases should be qualified. There is no indication that CHECWORKS has been thoroughly reviewed by the NRC or by a third party with no financial interest in the outcome of the review.

Dr. Horowitz provided no data that shows a comparison between CHECWORKS predictions and VY plant data prior to the power uprate. He stated that 4.5 years will be sufficient to assure that CHECWORKS will predict FAC reliably at the 20% power uprate. Dr. Horowitz provided no support whatsoever to this statement.

Q42. In your opinion, has Entergy satisfactorily addressed the major variables affecting the rates at which pipe thinning may occur?

A42. No, Entergy has failed to either take into account numerous physical phenomena affecting FAC, or to credibly explain why these well-known physical phenomena should not be considered in aging management of plant piping.

For example, despite overwhelming evidence to the contrary, Dr Horowitz denies that FAC is fundamentally a local phenomenon due to the variations of local turbulence in curved pipes, nozzles, tees, orifices, etc. *See,* Exhibits NEC –JH_53 at 48, 65 and NEC-JH_40 (It is common knowledge, for example, that the wall thinning on the extrados of elbows is considerably higher than on the intrados).

Further, Entergy's witness also denied (A47) that FAC varies with time and supported his claim with inadequate laboratory data because the test period was relatively very short. Data from longer tests, but still relatively short compared to plant life, show that corrosion rates generally vary with time. *See,* Exhibit NEC-JH_53 at 58.

These factors are important because they determine the scope of the FAC inspection program. Dr. Horowitz found it sufficient to dismiss these issues by summarily stating without supporting documentation (A42) that analytical work done by the industry and NSAC/CHECWORKS guidelines are adequate and sufficient and therefore a more thorough inspection with denser grids as discussed in my report, NEC-JH_36 at 15, is not required.

Q43. In your opinion, are there other factors affecting the prediction of pipe thinning that Entergy should have considered and yet failed to discuss?

A43. Yes, Entergy witness Dr. Horowitz did not address in a meaningful manner any of the following factors:

- How the effects of flow disturbances due to discontinuities, including those that were created by local corrosion, are accounted for in CHECWORKS
- How variation in local velocities in elbows, tees, orifices and nozzles are accounted for in grid size selection.
- How an empirical code such as CHECWORKS, which is based on data scatter of +60% and - 70%, can be considered a reliable predictive tool for corrosion rates.
- What is the scientific basis for component selection for the CHECWORKS program?
- What fraction of the total FAC-susceptible area is inspected during a typical plant outage?
- Why was there no significant reduction in total pipe failures from FAC following the release of CHECWORKS to the industry in mid 1987?

Q44. In considering aging management of piping, should a distinction be drawn between piping failures due to leaks and piping failures due to ruptures?

A44. Not really. Apparently to diminish the significance of failures from local corrosion, Dr. Horowitz makes a distinction (A47) between pipe failures due to leaks and failures from ruptures. It is absurd to make such a distinction without relating the "rupture" and the "leak" to a particular accident scenario. As an extreme example, under certain accident scenarios the aggregate flow from many small leaks in a pipe can exceed the choked flow from a single ruptured pipe. In any event, the NRC has not yet adopted the "leak before break" scenario. If Dr. Horowitz is trying to justify the use of CHECWORKS because leaks from local corrosion and failures in piping under 2 inches in diameter are less important than ruptures from larger diameter pipes, he should cite the appropriate authorities that reached such conclusions, or he should present the differences between leaks and ruptures in terms of their contribution to the core damage frequency.

Q45. Do you agree with Entergy's witness at A5 that FAC may be defined by excluding corrosion where there is [redacted] abrasion of the protective oxide layer at A5?

A45. I do not think that this is a practical definition of FAC. This is a very narrow definition of FAC that has been introduced in the last 15 years or so. Prior to that time, FAC was commonly referred to as erosion/corrosion. According to Dr. Horowitz's definition, FAC is defined as a process where there is no abrasion of the protective oxide layer. As discussed in Exhibit NEC-RH_03 at 8 and 9, the shear at the wall as a result of the velocity gradient can, if not destroy, definitely damage the protective oxide film. Therefore, there is no theoretical justification for such a narrowing of definitions. Moreover, there is no practical way to determine whether a given failure was caused by pure metal dissolution or in combination with oxide layer damage by shear- or cavitations-induced stresses. In areas where there is a large pressure drop, such as in discharge piping from pumps, both cavitations and FAC may cause wall thinning. Since, according to Dr. Horowitz, CHECWORKS is limited to predicting wall thinning by dissolution, only that type of potential pipe failure will be detected.

Dr. Horowitz also implies at A5 that small leaks result from erosion, not from FAC. I don't believe that this has been shown to be the case. The need to prevent wall thinning and piping leaks is dictated by safety considerations and not by selective and narrow definitions. Other causes of wall thinning (droplet impingement, cavitation, erosion, pitting) should not be excluded from inspection programs because CHECWORKS predictions of wall thinning do not account for such mechanisms.

Q46. At A34, Entergy's witness asserts that there is no need to calibrate CHECWORKS following the power uprate at VY. Did he provide support for this assertion?

A46. No. Dr. Horowitz provides no support for his assertion that there is no need to calibrate CHECWORKS following the power uprate at VY. As I have discussed in my report, Exhibit NEC-JH_36 at 4, the corrosion rate can vary by as much as the velocity to the 6th power .

Q47. At A38, Dr. Horowitz states that NEC is only concerned with CHECWORKS and not with the FAC program at VY. Is that a correct interpretation of NEC's position?

A47. No, it is not. NEC is concerned with the FAC program because its validity is based in large part on the use of CHECWORKS, which NEC considers unreliable. The scope of the FAC program, mainly how many components are inspected, what is the grid size, and how often to inspect a given component depend on the ability to predict corrosion rates. Since Entergy identified CHECKWORKS as the only tool that predicts and selects components for inspection, obviously CHECKWORKS is a focus of attention. Entergy never provided any specific information about other tools that are used to detect wall thinning.

Q48. At A39, 40 and 41, Dr. Horowitz denies that 10-15 years would be required to calibrate CHECWORKS. Does he provide supporting data? And do you now agree with his position?

A48. Entergy's witness provides absolutely no data to support his position. Paraphrasing the EPRI guidelines NSAC 202L and pointing out that VY has been collecting FAC data since 1989 does not explain how an empirical code, which presumably was calibrated under one set of operating conditions, can reliably predict FAC under different conditions without recalibration. Dr. Horowitz does not discuss how CHECWORKS meets the NRC requirements for using analytical codes in power plants. Such codes must be assessed and benchmarked against measured plant data. The benchmarking must be valid within the range in which the data was provided. Exhibit NEC-JH_35 at 190

I absolutely disagree with Entergy's witness. FAC in most cases is a slow process; the fact that some selected components have as yet shown no measurable wall thinning as a result of the uprate proves nothing. As pointed out in NEC –JH_36 at 15 and 16, this is the reason why 12 to 15 years would be required to monitor all the susceptible components to establish confidence in the ability of predicting the scope of FAC inspection during refueling outages.

Contrary to commonly accepted engineering principles, Entergy's witness insists that there is no need to calibrate the code even though plant conditions have changed. Further, even though he does not characterize it as calibration, Dr. Horowitz recognized the need to increase the inspection scope by 50% to account for the power uprate. He did not disclose, however, what fraction of the total FAC-susceptible area in the VY plant the proposed increased monitoring would represent.

Q49. At A42, Mr. Fitzpatrick and Dr. Horowitz claim that CHECWORKS and EPRI guidelines and 30 years of research have eliminated the need to increase the scope of FAC inspection as recommended by NEC. Are they correct?

A49. No. Entergy's witnesses failed to point out the hundreds of pipe failures both small and large in the last 30 years, including the Surry accidents. They dismiss many as not relevant because CHECWORKS was either not available or was not properly used. They failed to mention that EPRI guidelines were published before the Surry and the Trojan accidents. *See,* Erosion/Corrosion in Nuclear Steam Plant Piping: Causes and Inspection Program Guidelines, EPRI 3944s, April 1985.

Q50. Dr. Horowitz has complained at A39, A40 and A41 of his testimony that failures at San Onofre Unit 3, Millstone and Sequoyah were not included in the 16 years average described in Exhibit NEC-JH_36 at Table 2. How do you respond?

A50. Table 2 was not intended to cover all reactor accidents. It was focused primarily on major and risk-significant components and included both short exposure time and long exposure time failures. Contrary to Dr. Horowitz's statement, Sequoyah was included in Table 2. I agree with him that many more components could have been included in Table 2, however, I doubt that expanding the list would affect the conclusion that more than 15 years can pass before a major FAC-related failure would occur.

Q51. At A44, Dr. Horowitz appears to suggest that the oxygen concentration at VY did not change in 2003. Is he wrong?

A51. Yes, as shown below he is wrong, and his statements are misleading. *See,* Exhibit NEC-JH_36 at 15. VY did reduce the oxygen content in the plant in 2003. Exhibit NEC-JH_18 at 3.2 states the date when the switch from NWC to HWC was made. Entergy's CUFen calculations at lower oxygen concentrations, which NEC's Contentions 2A and 2B address, were based on that date. Plant data on oxygen concentrations show that, with the exception of the feedwater line, there was a significant reduction in oxygen in the plant. *See,* Exhibit NEC-JH_06 at A2.

Furthermore, [redacted]

If Dr. Horowitz restricts his comment to the feedwater line only, he is misrepresenting NEC's position, which clearly indicated that discussion was not restricted to the feedwater line.

Q52. At A45, Dr. Horowitz stated that he does not agree to the following statement you made in your report, Exhibit NEC-JH_36 at 15: "The observation that CHECWORKS can bound plant data between 100-200 mils/year . . . without specifying how each variable separately effects corrosion, does not address the issue of how the corrosion rate at a given location would be affected when the velocity changes by 20% at a given plant." How do you respond?

Even though the above is a key issue in NEC Contention 4, Dr. Horowitz finds it sufficient to provide a non-specific and non-quantitative reply. He completely ignores the lengthy discussion in my report, Exhibit NEC-JH_36 at 2-6.

Dr. Horowitz merely states at A45:

> As discussed above, the correlations built into CHECWORKS are based on laboratory experiments on modeled geometries, published correlations, and operating data from many nuclear units.

Dr. Horowitz did not provide any correlations that are used in CHECWORKS. And the data that was published (*See,* Exhibit NEC-JH_36 at 24) shows clearly that CHECWORKS predictions are not consistent with plant observations. Moreover, the predictions vary between + 60% and -

70%. Further, the predictions do not indicate how the local corrosion for a given component would be affected by changes in velocity.

Dr. Horowitz's reference E4-09 provides only a list of several plants with recent uprates above 15% and a statement that there were no major piping failures in the above plants. I emphatically do not agree with Entergy's witness that this somehow constitutes a scientific proof that CHECWORKS can predict FAC rates following changes in plant operating conditions. Again, he has neglected to indicate what fraction of the total piping would be included in the CHECWORKS program.

Q53. At A47, Dr. Horowitz states that you are incorrect that FAC is a non-linear phenomenon. Please respond.

A53. In my report, Exhibit NEC-JH_36 at 4 and 19, I provided an explanation as to why FAC varies locally and may not be linear. It should also be noted that the time scale for the nonlinearity was not specified in the model. Since FAC represents a slow process, the time scale may be on the order of years, not hours.

Dr. Horowitz cites Exhibit E4-19, Figures 7-6, and E-4-08 Figures 3-6 and 3-7. These figures do not support his statement by any stretch of the imagination. As discussed in Exhibit NEC-JH_36 at 5, laboratory data introduce scaling issues and the test duration is limited. The tests in E4-19 are short duration tests (500-2000 hrs). Even if one accepts Dr. Horowitz's argument that 4.5 years would be sufficient to benchmark CHECWORKS, the cited tests represent a time period which is only 1-5 % of the total time of interest. The tests were conducted on small mild steel specimens of unknown initial surface finish.

The extrapolation of the above results to real components (including plain carbon steel) that have been exposed to the reactor environment for 35 years under a range of operating conditions is ludicrous.

The tests in Figures E4-08, Figures 3-6 and 3-7, were conducted for an even shorter period of time (400-650 hrs). They were conducted to test the effect of copper ions on corrosion, and provide no information whatsoever on the linearity of FAC. Furthermore the corrosion rates were determined by measuring very small changes in activity of the specimen. They represent only the average corrosion rate at the surface of the entire specimen. This has nothing to do with the time-dependent phenomena discussed in my report, Exhibit NEC –JH_36 at 4 and 19.

At A47, Dr. Horowitz makes the following statement:

> With respect to the allegedly local nature of FAC wear, although local FAC wear is occasionally seen – normally near a geometric discontinuity – such local wear usually results in only minor effects (e.g., leaks). The normal feature of FAC wear – widespread wear over an extended area – is what causes significant problems (e.g. the need for pipe replacements or the occurrence of pipe ruptures).

Welds, entrance and exits to and from nozzles, elbows, and surface roughness, as discussed in Exhibit NEC –JH_36 at 4 and 19, are all discontinuities. I cannot fathom how Dr. Horowitz can imply that these are not important.

Dr. Horowitz also misinterprets the use of the word local. In the context of this discussion, "local" refers to pipe segments which can vary from a square inch or so to hundreds of square inches. It also can refer to surface discontinuities. Surfaces will exhibit a combination of uniform, smooth and rough areas. As already mentioned above, the corrosion in elbows is normally found on the extrados, whether or not it is uniform. The wall thinning is local with respect to the elbow and it can be approximately uniform within a given section of the component. When the corrosion is not linear with time and the corrosion attack can be highly local, it makes prediction of future rates and wall thickness measurements very difficult.

Dr. Horowitz is distracting from this issue by focusing on making distinctions between pipe ruptures and pipe leaks. His characterization of the failure at Surry is completely wrong. Dr. Horowitz stated at A47: "By contrast, at Surry, there was not localized wall thinning," and "The global nature of the FAC damage is consistent with experience of FAC induced rupture." Dr Horowitz is contradicted by a TVA document authored by D. W. Wilson, Project Engineer at Sequoyah. Referring to the Surry accident, Mr. Wilson stated: "The rupture was caused by localized wall thinning at a pipe to elbow weld. The thinning was identified as erosion-corrosion." Exhibit NEC-JH_70 at 2.

I personally have not conducted a detailed failure analysis, but I did notice the combination of uniform and non-uniform appearance of the elbow surfaces while visiting the Surry plant shortly after the accident in December 1986.

Dr. Horowitz appears to be confusing the nature of wall thinning with pipe rupture or a pipe leak. Whether a pipe ruptures or develops a small leak would depend on the degree of wall thinning and the nature and intensity of the applied loads. Making a distinction between a pipe rupture or a large leak is not important unless one can demonstrate that a given leak will not lead to a catastrophic core melt. The NRC has not yet accepted the concept of "leak before break." The three ruptures that Dr. Horowitz described at A47 occurred at normal operating conditions. A valid FAC program must also protect the pipes from <u>design basis</u> loads. It is apparent to me that Dr. Horowitz, though he is undeniably very zealous about CHECWORKS, has not considered the many different safety issues which are associated with wall thinning.

Q54. At A48, Dr. Horowitz disputes your view that it is the local velocity and not the calculated average velocity that controls local turbulence. Please respond.

A54. Dr. Horowitz misrepresents my view of this issue stated in Exhibit NEC-JH_36 at 3. It is incorrect for Dr. Horowitz to state that I have stated that a pressure drop across complex geometries would have required CFD type calculations because of my statement that wall thinning varies with the local characteristics of FAC. *See,* Exhibits NEC –JH_53 at 48, 65 and NEC-JH_40. I never stated that pressure drop calculations would commonly require CFD type analysis. The analogy with pressure drop is not valid, because here one is interested in the pressure drop across the entire component, not in the local variation of the pressure drop, experimental Kc values are sufficient to determine pumping requirements. Failures due to FAC are local and require the local velocity for valid assessment. A simple proof of this point is the fact that surfaces on the outer diameter of bends wear faster than those on the inner diameter. As pointed out in Exhibit NEC-JH_36 at 3, the average velocity may remain the same but the local corrosion rate may increase due to local geometry changes.

Table 3-1 and Table 7-1 in E4-08 contain average mass transfer coefficients as discussed in NEC-JH_36 at 2, 3 and 4. These coefficients can be obtained in any mass or heat transfer handbook; they have little to do with the determination of the local variation of corrosion rates in various components. This only indicates that CHECWORKS can be used as a general screening tool, i.e. comparing various geometries with respect to their vulnerability to FAC damage, a fact which NEC never denied. Figure 7-2 only verifies NEC's contention that corrosion rates vary with location depending on the intensity of the local turbulence. The factor A in that figure comes from EDF data and varies by an order of magnitude, depending on the component, with an RMS of 50%. A represents the total mass transfer coefficient, not the local variation of the mass transfer coefficient. The equation A =A + BxA is not referenced and its validity is not explained. It is apparently an attempt to account for local variations of turbulence under some unspecified condition. The above equation may be used for screening components but not to predict local corrosion rates as, for example, described in Exhibits NEC–JH_53 at 65 and NEC – JH_36 at 3, where the increase in the local turbulence intensifies the rate of corrosion. If wall thinning was measured at Unit 1 at the Ohi power station according to an equation of the type shown above, it would not have predicted the intense local thinning at the end of the curved section of the pipe. *See,* Exhibit NEC –JH_53 at 65.

Q55. NEC–JH_36 at 3 explained in detail that the local mass transfer coefficients in curved pipes in turbulent flow are expected to vary as the velocity square because turbulent mixing is promoted by the centrifugal force which varies with the square of the velocity. Also as indicated in NEC-JH_40 at Eq 22, erosion by droplet impingement varies with the square of droplet velocity At A49, Dr, Horowitz disputes this observation. How do you respond?

A55. Dr. Horowitz provided no relevant data to support his statement in A49. The figures in E4-22 and 23 do not dispute the dependence of the mass transfer coefficient in fully developed turbulent flow straight tubes and curved pipes. They are completely irrelevant to the issue raised by Q49.

With regard to my observation that the mass transfer coefficient varies with the 0.8^{th} power, Dr. Horowitz appears to agree by saying that the mass transfer varies between 0.5 and 1.0. The 0.5 is related to laminar flow and my observation was addressed to turbulent flow. Without providing any support, Dr. Horowitz makes the bald statement that the corrosion rate is directly proportional to the mass transfer coefficient. In NEC-JH_36 at 4 and 20, I discussed and provided a considerable amount of data showing that the corrosion rate may vary as the cube of the mass transfer coefficient, and therefore as a power of 2.4 to 6 of the velocity.

Dr. Horowitz's unsupported statement that data from all sources shows that erosion rate varies less than linearly is simply not true.

Q56. At A50, Dr. Horowitz states that "the successful use of CHECWORKS and it's [sic] predecessor programs for more than 20 years provides additional support for the claim that CHECWORKS is an effective tool for inspection planning." Please respond.

A56. The hundreds of pipe failures during this period, as documented by NEC, certainly do not support that statement. *See,* Exhibit NEC-JH_36 at 8, 9 and 10.

Q57. At A56, Dr. Horowitz comments on your statement that Entergy believes that "the length and the highest velocities control corrosion." Dr. Horowitz asserts that this quote is lifted from ACRS transcripts. Is he correct?

A57. Dr. Horowitz is wrong. This statement was not taken from ACRS transcripts. It is not taken out of context, nor is it misunderstood. The statement was made by Entergy directly in reply to NEC's Petition and not in a reply to the ACRS. *See,* Entergy's Answer to New England Coalition's Petition for Leave to Intervene, Request for Hearing, and Contentions (June 22, 2006) at 33.

Q58. Please list any references to this testimony that were not filed as Exhibits to your direct testimony.

A58.

1. Memorandum to H.L. Abercrombie, Site Director, Sequoyah Nuclear Plant from D.W. Wilson, Project Engineer, Sequoyah Nuclear Plant, "Sequoyah Nuclear Plant Units 1 and 2 – Preliminary Report on the Condensate-Feedwater Piping Inspection – Suspected Erosion-Corrosion Areas (January 27, 1987). Exhibit NEC-JH_70.

I also now submit two papers cited as references to my FAC report in support of NEC's Statement of Initial Position, Exhibit JH-NEC_36:

1. G.J. Bignold, et al, Paper 1, Water Chemistry II, BNES, 1980. Exhibit NEC-JH_71.
2. I.S. Woolsey. et. al., "Paper 96. The influence of oxygen and hydrazine on the erosion-corrosion behavior and electrochemical potentials of carbon steel under boiler feedwater conditions. Exhibit NEC-JH_72.

Q59. Does that complete your rebuttal testimony?

A59. Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Joram Hopenfeld, June 2, 2008
Joram Hopenfeld, PhD

At ____________, Maryland, this _______ day of May, 2008 personally appeared Joram Hopenfeld, and having subscribed his name acknowledges his signature to be his free act and deed.

Before me:

____

Notary Public

My Commission Expires ______________________

NEC-JH_64

ELECTRIC POWER RESEARCH INSTITUTE

Materials Reliability Program: Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application (MRP-47, Revision 1)

Technical Report

Materials Reliability Program: Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application (MRP-47 Revision 1)

1012017

Final Report, September 2005

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REPORT SUMMARY

For about the last 15 years, the effects of light water reactor environment on fatigue have been the subject of research in both the United States and abroad. Based on a risk study reported in NUREG/CR-6674, the NRC concluded that reactor water environmental effects were not a safety issue for a 60-year operating life, but that some limited assessment of its effect would be required for a license renewal extended operating period beyond 40 years. This guideline offers methods for addressing environmental fatigue in a license renewal submittal.

Background
Many utilities are currently embarking upon efforts to renew their operating licenses. One of the key areas of uncertainty in this process relates to fatigue of pressure boundary components. Although the NRC has determined that fatigue is not a significant contributor to core damage frequency, they believe that the frequency of pipe leakage may increase significantly with operating time and have requested that license renewal applicants perform an assessment to determine the effects of reactor water coolant environment on fatigue, and, where appropriate, manage this effect during the license renewal period. As the license renewal application process progressed starting in 1998, several utilities addressed this request using different approaches. In more recent years, a unified approach has emerged that has obtained regulator approval and allowed utilities to satisfactorily address this issue and obtain a renewed operating license for 60 years of plant operation.

Objectives
- To provide guidance for assessment and management of reactor coolant environmental effects
- To minimize the amount of plant-specific work necessary to comply with NRC requirements for addressing this issue in a license renewal application
- To provide "details of execution" for applying the environmental fatigue approach currently accepted by the NRC in the license renewal application process.

Approach
The project team reviewed previous work by EPRI and utilities related to fatigue environmental effects and license renewal including reports on this subject created by EPRI, NRC, and NRC contractors. Recent license renewal applications, NRC Requests for Additional Information, and the commitments made by the past license renewal applicants provided insight into NRC expectations. After evaluation of all this information, the project team developed alternatives for addressing fatigue environmental effects. This revision provides guidelines based on industry experience, consensus, and insight gained from more than six years of experience with this issue and the license renewal approval process.

Results

The report describes a fatigue environmental effect license renewal approach that can be applied by any license renewal applicant. It provides guidelines for performing environmental fatigue assessments using fatigue environmental factors from currently accepted F_{en} methodology.

EPRI Perspective

Utilities have committed significant resources to license renewal activities related to fatigue. Based on input from applicants to-date, NRC requirements for addressing fatigue environmental effects continued to change for the first few applicants, but more recently have become more unified. These guidelines were developed to provide stability, refined guidance, and assurance of NRC acceptance and include an approach that may be taken to address fatigue environmental effects in a license renewal application. Use of the approach provided in this document should limit the amount of effort necessary by individual license renewal applicants in addressing this requirement and putting activities in place for the extended operating period to manage reactor water environmental effects on fatigue.

Keywords

Fatigue
License Renewal
Reactor Water Environmental Fatigue Effects

ABSTRACT

For about the last 15 years, the effects of light water reactor environment on fatigue have been the subject of research in both the United States and abroad. The conclusions from this research are that the reactor water temperature and chemical composition (particularly oxygen content or ECP) can have a significant effect on the fatigue life of carbon, low alloy, and austenitic stainless steels. The degree of fatigue life reduction is a function of the tensile strain rate during a transient, the specific material, the temperature, and the water chemistry. The effects of other than moderate environment were not considered in the original development of the ASME Code Section III fatigue curves.

This issue has been studied by the Nuclear Regulatory Commission (NRC) for many years. One of the major efforts was a program to evaluate the effects of reactor water environment for both early and late vintage plants designed by all U.S. vendors. The results of that study, published in NUREG/CR-6260, showed that there were a few high usage factor locations in all reactor types, and that the effects of reactor water environment could cause fatigue usage factors to exceed the ASME Code-required fatigue usage limit of 1.0. On the other hand, it was demonstrated that usage factors at many locations could be shown acceptable by refined analysis and/or fatigue monitoring of actual plant transients.

Based on a risk study reported in NUREG/CR-6674, the NRC concluded that reactor water environmental effects were not a safety issue for a 60-year operating life, but that some limited assessment of its effect would be required for a license renewal extended operating period beyond 40 years. Thus, for all license renewal submittals to-date, there have been formal questions raised on the topic of environmental fatigue and, in all cases, utility commitments to address the environmental effects on fatigue in the extended operating period. Many plants have already performed these commitments.

This guideline offers methods for addressing environmental fatigue in a license renewal submittal. It requires that a sampling of the most affected fatigue sensitive locations be identified for evaluation and tracking in the extended operating period. NUREG/CR-6260 locations are considered an appropriate sample for F_{en} evaluation as long as none exceed the acceptance criteria with environmental effects considered. If this occurs, the sampling is to be extended to other locations. For these locations, evaluations similar to those conducted in NUREG/CR-6260 are required. In the extended operating period, fatigue monitoring is used for the sample of locations to show that ASME Code limits are not exceeded. If these limits are exceeded, corrective actions are identified for demonstrating acceptability for continued operation.

Using the guidance provided herein, the amount of effort needed to justify individual license renewal submittals and respond to NRC questions should be minimized, and a more unified, consistent approach should be achieved throughout the industry. More importantly, this revision provides "details of execution" for applying the environmental fatigue approach currently accepted by the NRC in the license renewal application process.

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1 INTRODUCTION

1.1 Objectives

The nuclear industry has discussed the issue of reactor water environmental fatigue effects with the U. S. Nuclear Regulatory Commission (NRC) staff for several years. All of the license renewal applicants to-date have been required to commit to an approach to evaluate the effects of reactor water environment on specific Class 1 reactor coolant system components for the license renewal term in order to obtain approval for a renewed license.

This report provides discussion of an approach that may be used for addressing reactor water environmental effects on fatigue of reactor coolant system components in the extended operating period (after 40 years). Specific guidance for calculating environmental fatigue usage factors for NUREG/CR-6260 [2] locations is provided using the methodology documented in NUREG/CR-6583 [3] and NUREG/CR-5704 [4]. This report does not provide guidance on addressing fatigue as a Time Limiting Aging Analysis (TLAA) per 10CFR54. The details of monitoring thermal fatigue for acceptance are contained in Reference [23].

Thus, the objectives of this report are as follows:

1. To provide guidance for evaluating the effects of reactor water environmental effects on fatigue for license renewal applicants,
2. To provide specific guidance on the use of NUREG/CR-6583 for carbon and low alloy steels [3] and in NUREG/CR-5704 for austenitic stainless steels [4] in plant specific evaluations of the effects of reactor water environmental effects on fatigue,
3. To provide separate guidance for pressurized water reactors (PWRs) and boiling water reactors (BWRs) to assist in the development of reasonable estimates for the significant parameters (e.g., oxygen, temperature, and strain rate) required by the environmental fatigue assessment methodology at evaluated locations,
4. To provide approaches for removing excess conservatism in existing fatigue analyses to offset the impact of environmental effects,
5. To provide alternatives for managing environmental effects using flaw tolerance evaluation and inspection,
6. To provide guidance that minimizes the amount of effort needed to justify individual license renewal submittals and respond to NRC questions, and promote a more unified, consistent approach throughout the industry, and
7. Incorporate "Lessons Learned" from ASME Code activities supported by the MRP associated with this topic.

This guideline document includes appropriate logic to allow users to efficiently perform environmental fatigue calculations for a plant pursuing license renewal activities. The logic is provided such that some components can be evaluated using simplified methods, whereas others can be evaluated using more complex methods.

Finally, this document also summarizes the approaches for addressing fatigue environmental effects in the extended operating period used by those applicants that have already submitted the license renewal applications.

1.2 Compliance Responsibilities

The Industry Guidelines contained in this report are considered to be "Good Practice".

2 BACKGROUND

2.1 Research Results

NRC research in the area of reactor water environmental effects on fatigue began in the early 1990s. Based on testing both in Japan and in the U.S., fatigue life in a light water reactor (LWR) environment was determined to be adversely affected by certain water chemistries, strain amplitude, strain rate, temperature and material sulfur content (for ferritic steels). Whereas LWR pressure boundary components are in contact with the reactor water at elevated temperatures, the fatigue curves in Section III of the ASME Boiler and Pressure Vessel Code were based on testing in air, primarily at room temperature, adjusted by a structural factor in-part to compensate for temperature and "industrial" environments. In 1993, a set of "interim" fatigue curves for carbon, low alloy, and stainless steels were published in NUREG/CR-5999 [1] based on the results of research testing at that point in time.

To determine the effects of the environment in operating nuclear plants during the current 40-year licensing term and for an assumed 60-year extended period, Idaho National Engineering Laboratories (INEL) evaluated fatigue-sensitive component locations, and documented their results in NUREG/CR-6260 [2]. Using information from existing reactor component stress reports, supplemented by additional evaluations, cumulative fatigue usage factors (CUFs) were calculated for plants designed by all four nuclear steam supply system (NSSS) vendors utilizing the interim fatigue curves provided in NUREG/CR-5999 [1]. The results showed that CUFs would exceed 1.0 at several locations, although the CUFs at many of these were shown to be less than 1.0 if excessive conservatisms were removed from the evaluations.

Continued research led to changes to the fatigue curves utilized in deriving the results presented in NUREG/CR-6260 [2]. The latest proposed environmental fatigue correlations are presented in NUREG/CR-6583 [3] for carbon and low alloy steels and in NUREG/CR-5704 [4] for austenitic stainless steels. These approaches do not use the revised fatigue curve approach originally defined in NUREG/CR-5999, but instead employ a selective environmental fatigue multiplier, or F_{en}, approach that is defined as follows:

$$F_{en} = \frac{N_{air}}{N_{water}}$$

where:

F_{en} = environmental fatigue multiplier

N_{air} = fatigue life (number of cycles) in air, at room temperature

N_{water} = fatigue life (number of cycles) in water (environment), at temperature

The fatigue usage derived from air curves is multiplied by F_{en} to obtain the fatigue usage in the associated environment.

More recently, an evaluation was conducted to assess the implications of LWR environments on reducing component fatigue for a 60-year plant life. This study, based on the information in NUREG/CR-6260 [2] and documented in NUREG/CR-6674 [5], concluded that the environmental effects of reactor water on fatigue curves had an insignificant contribution to core damage frequency. However, the frequency of pipe leakage was shown to increase in some cases.

2.2 License Renewal Environmental Fatigue Issue

The environmental fatigue issue for license renewal reached the current disposition via the closeout of Generic Safety Issue 190 (GSI-190) [6] in December 1999. In a memorandum from NRC-RES to NRC-NRR [7], it was concluded that environmental effects would have a negligible impact on core damage frequency, and as such, no generic regulatory action was required. However, since NUREG/CR-6674 [5] indicated that reactor coolant environmental fatigue effects would result in an increased frequency of pipe leakage, the NRC required that utilities applying for license renewal must address the effects of reactor water environments on fatigue usage in selected examples of affected components on a plant specific basis.

2.3 Industry/EPRI Programs

Following the issuance of NUREG/CR-6260 [2], EPRI performed several studies to quantitatively address the issue of environmental fatigue during the license renewal period.

The initial efforts were focused on developing a simplified method for addressing environmental fatigue effects and evaluating more recent research results. The calculations reported in NUREG/CR-6260 [2] were based on the interim fatigue design curves given in NUREG/CR-5999 [1]. The conservative approach in NUREG/CR-6260 [2] and NUREG/CR-5999 [1] over-penalized the component fatigue analysis, since later research identified that a combination of environmental conditions is required before reactor water environmental effects become pronounced. The strain rate must be sufficiently low and the strain range must be sufficiently high to cause repeated rupture of the protective oxide layers that protect the exposed surfaces of reactor components. Temperature, dissolved oxygen content, metal sulfur content, and water flow rate are examples of additional variables to be considered.

In order to take these parameters into consideration, EPRI and GE jointly developed a method, commonly called the F_{en} approach [8], which permits reactor water environmental effects to be applied selectively, as justified by evaluating the combination of effects that contribute to increased fatigue susceptibility.

The F_{en} approach was used in several EPRI projects to evaluate fatigue-sensitive component locations in four types of nuclear power plants: an early-vintage Combustion Engineering (CE) PWR [9], an early-vintage Westinghouse PWR [10], and both late-vintage [11] and early-vintage [12] General Electric (GE) BWRs. Component locations similar to those evaluated in NUREG/CR-6260 [2] were examined in these generic studies.

The NRC staff has not accepted the studies performed by EPRI [13], primarily because the environmental fatigue effects were based on data that was developed prior to the issuance of later reports by Argonne National Laboratory (ANL) [3, 4]. The following issues were raised in a letter from NRC to the Nuclear Energy Institute [13]:

- The environmental fatigue correction factors developed in the EPRI studies were not based on the latest ANL test report.
- The environmental factors developed in the EPRI studies were not based on a comparison of environmental data at temperature to air data at room temperature.
- The NRC did not agree with the use of the reduction factors (Z-factors) of four (for carbon steel) and two (for stainless steel) to account for moderate environmental effects (i.e., $F_{en,\,effective} = F_{en}$/Z-factor). Instead, the NRC staff believed that the maximum factors that could be used were three (for carbon steel) and 1.5 (for stainless steel).
- There was disagreement on the strain thresholds that were used.
- The NRC staff did not agree that credit could be taken for the cladding in omitting consideration of environmental effects for the underlying carbon steel/low alloy steel materials, unless fatigue in the cladding was specifically addressed.
- The staff agreed with the use of a weighted average strain rate for computing environmental effects only if the maximum temperature of the transient was used.

Based on NRC review of more recent Japanese and ANL data, NRC believes that no credit should be given for inherent margins with regard to moderate environmental effects [14], i.e., the above factor of 4 (EPRI)/3 (NRC) for carbon and low alloy steels, and 2/1.5 for stainless steels should not exceed 1.0.

The Pressure Vessel Research Council (PVRC) Steering Committee on Cyclic Life and Environmental Effects (CLEE) has reviewed published environmental fatigue test data and the F_{en} methodology. Based on this review, the most recent findings by ANL have been incorporated into the equations for the environmental factors. More importantly, it was concluded that the environmental factors could be reduced, by factors of 3.0 for carbon/low-alloy steel and 1.5 for stainless steel, to credit moderate environmental effects included in the current ASME Code fatigue design curves. The PVRC recommendations have been forwarded to the Board of Nuclear Codes and Standards (BNCS) [15]. The recommended evaluation procedure is published in Welding Research Council (WRC) Bulletin No. 487 [18]. WRC-487 includes evaluations based on recent data that would support reduction factors of 3.0 for carbon/low-alloy steel and 1.5 for stainless steel.

In conjunction with the PVRC efforts, the MRP reviewed all published industry fatigue data and documented their review of the data and recommended assessment methodologies [19]. Based on those findings, in 2003, the industry pursued a formal response to the NRC regarding the above areas of disagreement for carbon and low alloy steels [20]. The NRC staff ruled against this response in January 2004 [21] citing that an adequate technical basis was not provided to support several of the assumptions used in the industry's proposal. As a result, EPRI has chosen to work with the license renewal applicants on an industry guideline that defines evaluation techniques that plants can use to satisfactorily achieve resolutions to the issues. These prototype resolutions are formulated for use with F_{en} expressions whether from NRC, NUREG, PVRC or other sources, with discussion provided for the NUREG methodology since that methodology is currently accepted for use by license renewal applicants. The industry is pursuing longer-term application of the PVRC rules through ASME Code changes.

3
LICENSE RENEWAL APPROACH

3.1 Overview

This document describes how the technical issues associated with reactor water fatigue environmental effects evaluation may be addressed, and guidelines are provided on how to perform environmental fatigue evaluations using the methodologies documented in NUREG/CR-6583 [3] and NUREG/CR-5704 [4]. To assess the effects of reactor water environment on fatigue life, a limited number of components (including those in NUREG/CR-6260 [2] for the appropriate vintage/vendor plant) are to be assessed considering the effects of recent environmental fatigue data. As explained below, NUREG/CR-6260 locations are considered an appropriate sample for F_{en} evaluation as long as none exceed the acceptance criteria with environmental effects considered. If this occurs, the sampling is to be extended to other locations. These component locations serve as the leading indicators to assess the significance of environmental effects. For this limited number of components, the effects of the environment on fatigue life must be addressed and adequately managed in the extended operating period.

The process chosen to address environmental effects by the first few applicants for license renewal varied. After a series of requests for additional information, the process that the NRC accepted for Calvert Cliffs and Oconee involved an analytical approach coupled with future planned refinements in their plant fatigue monitoring. Since that time, there has been acceptance of the approaches used by other applicants, and some applicants have committed to perform evaluation only just before entering into the license renewal period (i.e., prior to the end of 40 years). Appendix A provides the results of an industry survey of license renewal applicants to-date describing the varied approaches that have been used.

In many cases, the commitment to perform evaluation later by some of the license renewal applicants has been based on uncertainty and lack of consensus on this topic throughout the industry, and reflects a "wait-and-see" attitude and an avoidance of expending resources now on an issue that may change later. Therefore, it is the intent of this report to develop guidelines for aging management of reactor water fatigue effects for license renewal, so that an acceptable and more unified approach for addressing this issue will be clearly documented for future license renewal applicants.

These guidelines provide a process to address environmental effects in the License Renewal Application, and provide specific guidance on the use of currently accepted environmental fatigue evaluation methodologies. Where necessary, these guidelines are consistent with the Thermal Fatigue Licensing Basis Monitoring Guidelines [23], based on today's knowledge and industry experience. The elements of this approach may change in the future as more information becomes available. Attributes of the fatigue management activity are as follows:

1. SCOPE

   The scope is discussed in detail in Section 2.5.2 of Reference [23]. NUREG/CR-6260 locations will be captured and thus automatically included by the activity steps discussed therein.

2. PREVENTIVE ACTIONS

   Cracking due to thermal fatigue of locations specifically designed to preclude such cracking is prevented by assuring that the thermal fatigue licensing basis remains valid for the period of extended operation. The actions taken in Thermal Fatigue Licensing Basis Monitoring are based on reliance on the standards established in ASME Section III and ASME Section XI.

3. PARAMETERS MONITORED OR INSPECTED

   Monitored parameters are defined and discussed in detail in Sections 2.5.2 and 2.6 of Reference [23].

4. DETECTION OF AGING EFFECTS

   The only detectable aging effects of fatigue are the presence of cracks. These cracks may initiate earlier in life and grow to a detectable size sometime after the CUF exceeds 1.0. The Inservice Inspection Plan as governed by ASME Section XI administers a set of actions relative to the inspection for, detection of, and disposition of crack like indications. This guideline is a sister guideline to the Thermal Fatigue Licensing Basis Monitoring Guideline but is not a part of it.

   The Thermal Fatigue Licensing Basis Monitoring Guideline tracks the margin allotted to the point of CUF = 1 (or to a lesser threshold point) as a way of tracking the life expended prior to the onset of structurally relevant fatigue cracking. Refer to Sections 2.5.2 and 2.6 of Reference [23] for a discussion of the parameters monitored for this purpose.

5. MONITORING & TRENDING

   Sections 2.5.2 and 2.6 of Reference [23] provide a discussion of the parameters monitored and the trending of those parameters as the component fatigue life is expended.

6. ACCEPTANCE CRITERIA

   Sections 2.5.2 and 2.6 of Reference [23] provide a discussion of the parameters monitored, the establishment of acceptance criteria for those parameters, and the trending of those parameters as the component fatigue life is expended.

7. CORRECTIVE ACTION

   Section 2.6.3 of Reference [23] provides a detailed discussion of the application of the corrective action requirements.

8. CONFIRMATION PROCESS

   The confirmation process is part of the corrective action program.

9. ADMINISTRATIVE CONTROLS

   The Thermal Fatigue Licensing Basis Monitoring Guideline actions are implemented by plant work processes.

10. OPERATING EXPERIENCE

    Refer to Sections 1.1 and 2.5.2.3 of Reference [23] for a discussion of how operating experience becomes part of the Thermal Fatigue Licensing Basis Monitoring Guideline implementation.

3.2 Method for Evaluation of Environmental Effects

There are several methods that have been published to assess the effects of reactor water environment on fatigue for each specific location to be considered. In this document, guidance is provided for performing evaluations in accordance with NUREG/CR-6583 [3] for carbon and low alloy steels and NUREG/CR-5704 [4] for austenitic stainless steels, since these are the currently accepted methodologies for evaluating environmental fatigue effects. Other methods that have been published, including those currently being used in Japan, are documented in References [18] and [22].

Figure 3-1 is a flowchart that shows an overview of the assessment approach.

- The first step is to identify the locations to be used in the assessment. This step is discussed in Section 3.2.1
- The second step is to perform an assessment of the effects of environmental fatigue on the locations identified in Step 1. This includes an assessment of the actual expected fatigue usage factor including the influence of environmental effects. Inherent conservatisms in design transients may be removed to arrive at realistic CUFs that include environmental effects. This approach is most applicable to locations where the design transients significantly envelope actual operating conditions in the plant. Further discussion is provided in Section 3.2.2. Specific guidance on performing such evaluation is provided in Section 4.0.
- The bottom of Figure 3-1 indicates that fatigue management occurs after the evaluation from Step 2 is performed for each location. This may be as simple as counting the accumulated cycles and showing that they remain less than or equal to the number of cycles utilized in the assessment performed in Step 2. On the other hand, it may not be possible to show continued acceptance throughout the extended operating period such that additional actions are required. Such options are discussed in Section 3.3. Refer also to Reference [23] for a discussion of cycle counting.

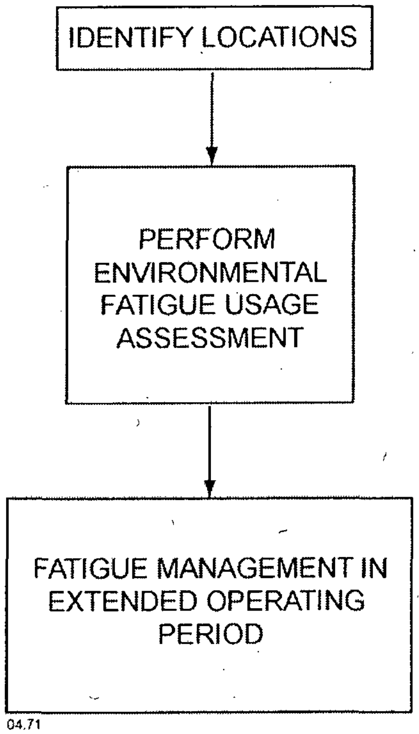


Figure 3-1
Overview of Fatigue Environmental Effects Assessment and Management

3.2.1 Identification of Locations for Assessment of Environmental Effects

A sampling of locations is chosen for the assessment of environmental effects. The purpose of identifying this set of locations is to focus the environmental assessment on just a few components that will serve as leading indicators of fatigue reactor water environmental effects. Figure 3-2 shows an overview of the approach identified for selecting and evaluating locations.

For both PWR and BWR plants, the locations chosen in NUREG/CR-6260 [2] were deemed to be representative of locations with relatively high usage factors for all plants. Although the locations may not have been those with the highest values of fatigue usage reported for the plants evaluated, they were considered representative enough that the effects of LWR environment on fatigue could be assessed.

The locations evaluated in NUREG/CR-6260 [2] for the appropriate vendor/vintage plant should be evaluated on a plant-unique basis. For cases where acceptable fatigue results are demonstrated for these locations for 60 years of plant operation including environmental effects, additional evaluations or locations need not be considered. However, plant-unique evaluations may show that some of the NUREG/CR-6260 [2] locations do not remain within allowable limits for 60 years of plant operation when environmental effects are considered. In this situation, plant specific evaluations should expand the sampling of locations accordingly to include other locations where high usage factors might be a concern.

In original stress reports, usage factors may have been reported in many cases that are unrealistically high, but met the ASME Code requirement for allowable CUF. In these cases, revised analysis may be conducted to derive a more realistic usage factor or to show that the revised usage factor is significantly less than reported.

If necessary, in identifying the set of locations for the expanded environmental assessment, it is important that a diverse set of locations be chosen with respect to component loading (including thermal transients), geometry, materials, and reactor water environment. If high usage factors are presented for a number of locations that are similar in geometry, material, loading conditions, and environment, the location with the highest expected CUF, considering typical environmental fatigue multipliers, should be chosen as the bounding location to use in the environmental fatigue assessment. Similar to the approach taken in NUREG/CR-6260 [2], the final set of locations chosen for expanded environmental assessment should include several different types of locations that are expected to have the highest CUFs and should be those most adversely affected by environmental effects. The basis of location choice should be described in the individual plant license renewal application.

In conclusion, the following steps should be taken to identify the specific locations that are to be considered in the environmental assessment:

- Identify the locations evaluated in NUREG/CR-6260 [2] for the appropriate vintage/vendor plant.
- Perform a plant-unique environmental fatigue assessment for the NUREG/CR-6260 locations.
- If the CUF results for all locations above are less than or equal to the allowable (typically 1.0) for the 60-year operating life, the environmental assessment may be considered complete; additional evaluations or locations need not be considered.
- If the CUF results for any locations above are greater than the allowable for the 60-year operating life, expand the locations evaluated, considering the following:
  - Identify all Class 1 piping systems and major components. For the reactor pressure vessel, there may be multiple locations to consider.
  - For each system or component, identify the highest usage factor locations. By reasons of geometric discontinuities or local transient severity, there will generally be a few locations that have the highest usage factors when considering environmental effects.
  - From the list of locations that results from the above steps, choose a set of locations that are a representative sampling of locations with the highest expected usage factors when considering environmental effects. Considerations for excluding locations can include: (1) identification of excess conservatism in the transient grouping or other aspects of the design fatigue analysis, or (2) locations that have similar loading conditions, geometry, material, and reactor water environment compared to another selected location.

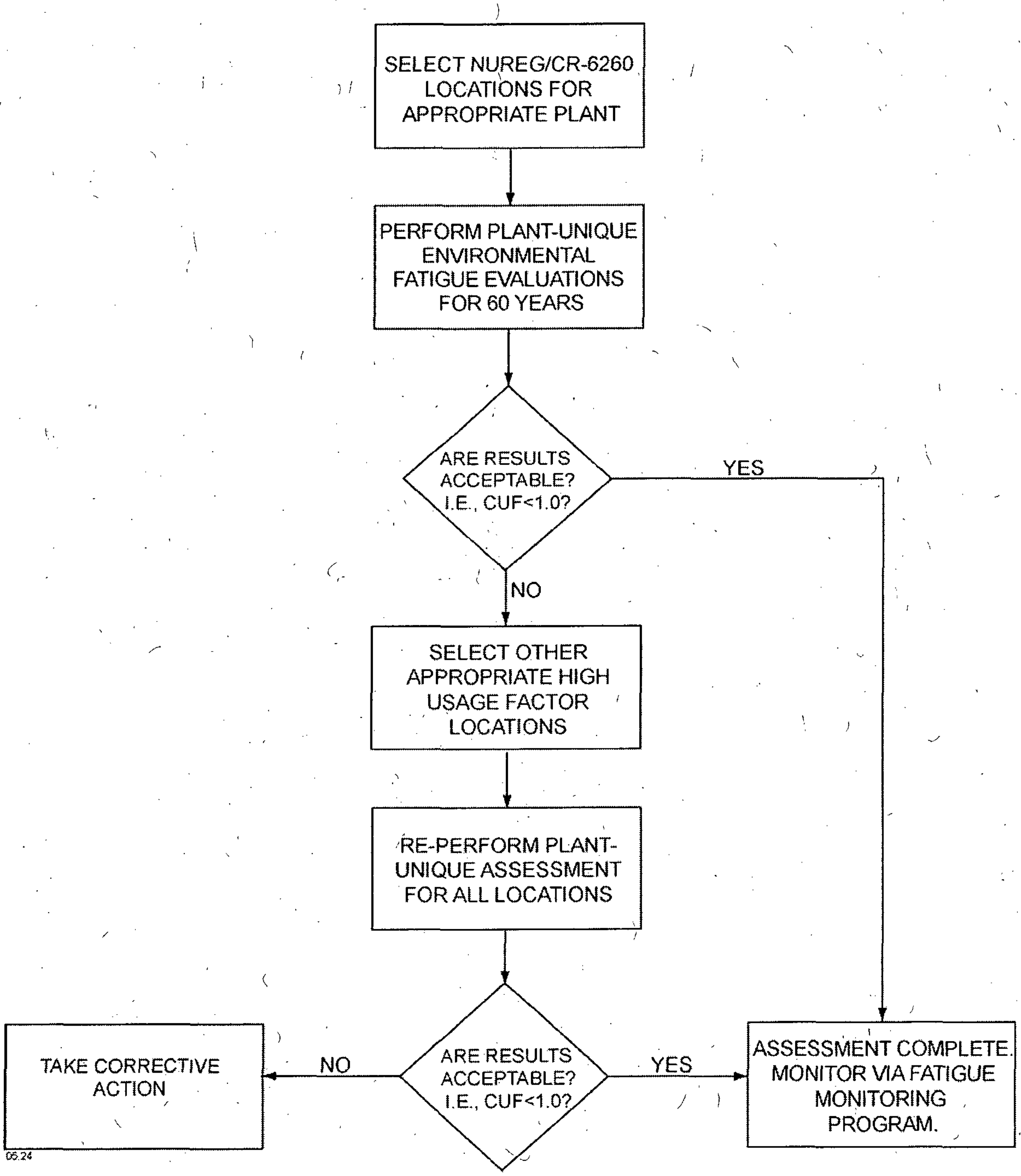


Figure 3-2
Identification of Component Locations and Fatigue Environmental Effects Assessment

3.2.2 Fatigue Assessment Using Environmental Factors

In performing an assessment of environmental fatigue effects, factors to account for environmental effects are incorporated into an updated fatigue evaluation for each selected location using the F_{en} approach documented in NUREG/CR-6583 [3] for carbon and low alloy steels and NUREG/CR-5704 [4] for austenitic stainless steels. Excess conservatism in the loading definitions, number of cycles, and the fatigue analyses may be considered. Figure 3-3 shows the approach for performing the assessment and managing fatigue in the extended operating period.

Determination of Existing Licensing Basis

Existing plant records must be reviewed to determine the cyclic loading specification (transient definition and number of cycles) and stress analysis for the location in question. Review of the analysis may or may not show that excess conservatism exists. Reference [23] provides guidance on reviewing the original design basis, the operating basis, and additions imposed by the regulatory oversight process, to determine the fatigue licensing basis events for which the component is required to be evaluated.

Consideration of Increased Cycles for Extended Period

As a part of the license renewal application process, the applicant must update the projected cycles to account for 60 years of plant operation. The first possible outcome is that the number of expected cycles in the extended operating period will remain at or below those projected for the initial 40-year plant life. In this case, the governing fatigue analyses will not require modification to account for the extended period of operation.

The second possibility is that more cycles are projected to occur for 60 years of plant operation than were postulated for the first 40 years. In this case, an applicant must address the increased cycle counts. One possible solution is to perform a revised fatigue analysis to confirm that the increased number of cycles will still result in a CUF less than or equal to the allowable. A second possibility is to determine the number of cycles at which the CUF would be expected to reach the allowable. This cycle quantity then becomes the allowable against which the actual operation is tracked. Section 3.3 discusses options to be employed if this lower allowable is projected to be exceeded.

Fatigue Assessment

Fatigue assessment includes the determination of CUF considering environmental effects. This may be accomplished conservatively using information from design documentation and bounding F_{en} factors from NUREG/CR-6583 [3] and NUREG/CR-5704 [4], or it may require a more extensive approach (as discussed in Section 4.0).

A revised fatigue analysis may or may not be required. Possible reasons for updating the fatigue analysis could include:

- Excess conservatism in original fatigue analysis with respect to modeling, transient definition, transient grouping and/or use of an early edition of the ASME Code.

- For piping, use of an ASME Code Edition prior to 1979 Summer Addenda, which included the ΔT_1 term in Equation (10) of NB-3650. Use of a later code reduces the need to apply conservative elastic-plastic penalty factors.
- Re-analysis may be needed to determine strain rate time histories possibly not reported in existing component analyses, such that bounding environmental multipliers (i.e., very low or "saturated" strain rates) would not have to be used.

A simplified revised fatigue analysis may be performed using results from the existing fatigue analysis, if sufficient detail is available. Alternatively, a new complete analysis could be conducted to remove additional conservatisms. Such an evaluation would not necessarily need the full pedigree of a certified ASME Code Section III analysis (i.e., Certified Design Specification, etc.), but it should utilize all of the characteristic methods from Section III for computing CUF. In the environmental fatigue assessment, the environmental fatigue usage may be calculated using the following steps:

- For each load set pair in the fatigue analysis, determine an environmental factor F_{en}. This factor should be developed using the equations in NUREG/CR-6583 [3] or NUREG/CR-5704 [4]. (Section 4.0 provides specific guidance on performing an F_{en} evaluation)
- The environmental partial fatigue usage for each load set pair is then determined by multiplying the original partial usage factor by F_{en}. In no case shall the F_{en} be less than 1.0.
- The usage factor is the sum of the partial usage factors calculated with consideration of environmental effects.

Fatigue Management Approach

As shown in Figure 3-3, the primary fatigue management approaches for the extended operating period consist of tracking either the CUF or number of accumulated cycles.

- For cycle counting, an updated allowable number of cycles may be needed if the fatigue assessment determined the CUF to be larger than allowable. One approach is to derive a reduced number of cycles that would limit the CUF to less than or equal to the allowable value (typically 1.0). On the other hand, if the assessed CUF was shown to be less than or equal to the allowable, the allowable number of cycles may remain as assumed in the evaluation, or increased appropriately. As long as the number of cycles in the extended operating period remains within this allowed number of cycles, no further action is required.
- For CUF tracking, one approach would be to utilize fatigue monitoring that accounts for the actual cyclic operating conditions for each location. This approach would track the CUF due to the actual cycle accumulation, and would take credit for the combined effects of all transients. Environmental factors would have to be factored into the monitoring approach or applied to the CUF results of such monitoring. No further action is required as long as the computed usage factor remains less than or equal to the allowable value.

Prior to such time that the CUF is projected to exceed the allowable value, or the number of actual cycles is projected to exceed the allowable number of cycles, action must be taken such that the allowable limits will not be exceeded. If the cyclic or fatigue limits are expected to be exceeded during the license renewal period, further approaches to fatigue management would be required prior to reaching the limit, as described in Section 3.3. Further details on guidelines for thermal fatigue monitoring and compliance/mitigation options are provided in Reference [23].

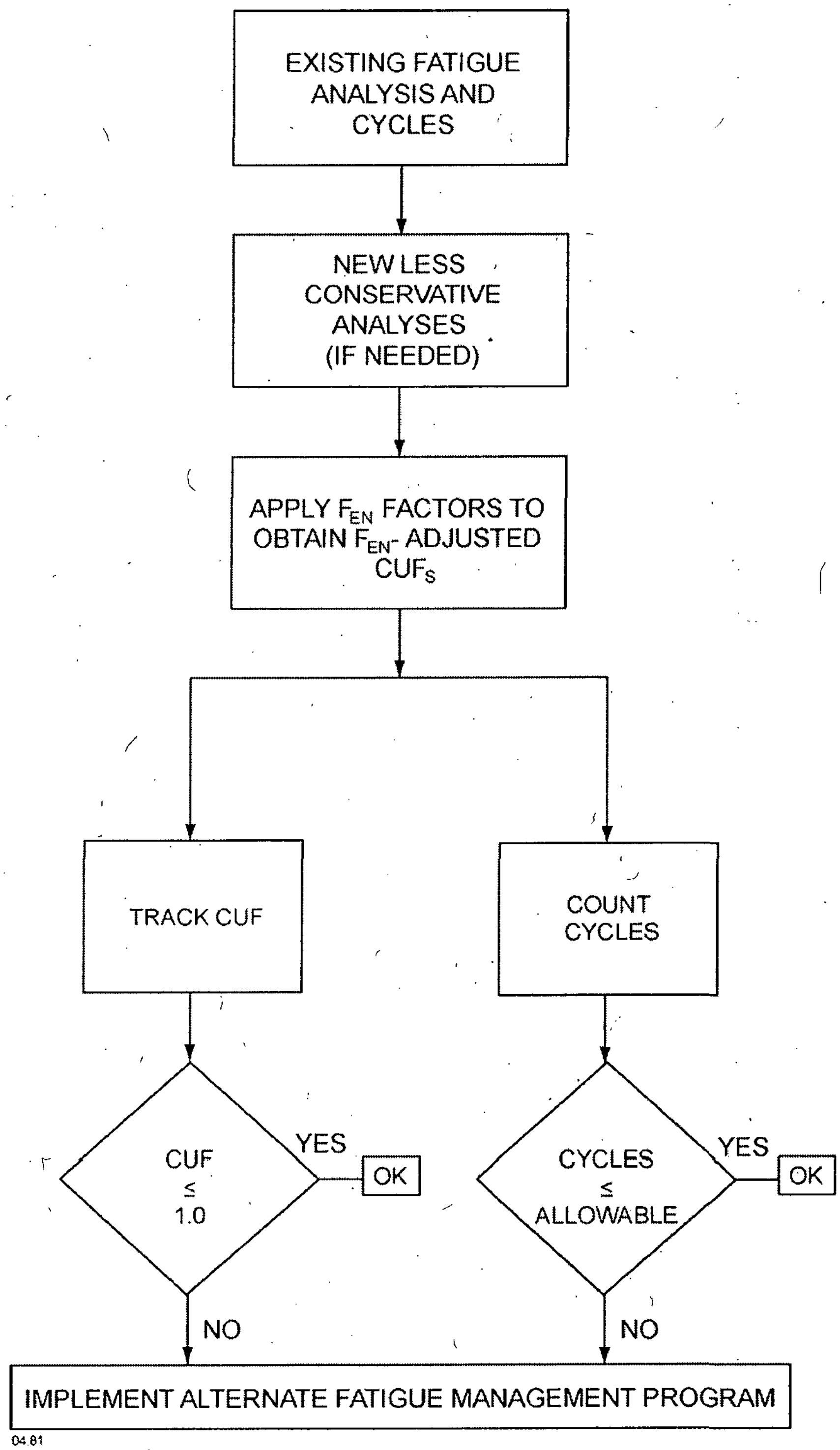


Figure 3-3
Fatigue Management if Environmental Assessment Conducted

3.3 Alternate Fatigue Management in the License Renewal Period

As identified in Section 3.2, and discussed in detail in Reference [23], results from cycle counting or fatigue monitoring may predict that established limits are exceeded during the extended operating period. If this occurs, there are several alternative approaches which may be used to justify continued operation with the affected component in service without having to perform repair or replacement, as follows:

- Reanalysis
- Partial Cycle Counting
- Fatigue Monitoring
- Flaw Tolerance Evaluation and Inspection
- Modified Plant Operations
- Evaluation of Similar Components

In addition, the fatigue management program may need to be expanded if plant-unique or industry experience shows that fatigue limits are exceeded or if cracking is discovered, due to either anticipated or unanticipated transients. Refer to Reference [23] for a comprehensive discussion of these items.

3.4 Guidance for Plants with B31.1 Piping Systems

Many plants that were designed in the 1960s had piping systems that were designed in accordance with the rules of the ANSI B31.1 Power Piping Code. This Code did not require an explicit fatigue analysis. However, the effects of thermal expansion cycles were included. If the number of equivalent full range thermal expansion cycles was greater than 7,000, the allowable range of thermal expansion stress was reduced. There was no consideration of stresses due to through-wall thermal gradients, axial temperature gradients, or bi-metallic welds.

Although ANSI B31.1 and ASME Code, Section III, Class 1 piping rules are fundamentally different, experience in operating plants has shown that piping systems designed to B31.1 are adequate. An evaluation of fatigue-sensitive B31.1 piping systems by EPRI [17] showed that there were only very limited locations in piping systems that exhibited high usage factors. In each case, these locations could be easily identified. It was concluded that high usage factors occurred only at locations that experienced significant thermal transients such as step temperature changes. In addition, the locations with high usage factors were always at a structural or material discontinuity, such as pipe-to-valve or pipe-to-nozzle transition welds. The report also noted that the design features of B31.1 plants are essentially no different than those in more modern plants designed to ASME Code, Section III, Class 1.

The high usage factor locations evaluated in NUREG/CR-6260 [2] were primarily associated with piping system discontinuities and occurred due to severe transients, except for PWR surge lines where a high number of stratification transients contributed to high usage factors.

The operation of B31.1 plants is also not different from that of plants designed to ASME Code, Section III, Class 1. All have limitations on heatup/cooldown rates as required by ASME Code, Sections III and XI, and 10CFR50 Appendix G. The NSSS vendors have also provided continued feedback to plant operators to reduce the thermal fatigue challenges to components based on industry experience. Thus, the approach taken by an applicant with ANSI B31.1 piping systems need not be significantly different than that taken for a more modern plant:

- The locations of NUREG/CR-6260 [2] for the appropriate vintage/vendor plant are selected. For systems without specified design transients, a set of transients for tracking in the extended operating period must be established.
- Evaluations shall be undertaken to establish the usage factors at each of the selected locations. This may be based on similarities in geometry, materials, and transient cycles relative to other similarly designed plants. In addition, the information provided in NUREG/CR-6260 [2] may be used. Alternately, an ASME Code, Section III, Class 1 analysis can be conducted. Such an evaluation would not necessarily need the full pedigree of a certified ASME Code, Section III analysis (i.e., Certified Design Specification, etc.), but it should utilize all of the characteristic methods from Section III for computing CUF. Such an analysis would be used to establish the baseline fatigue usage without environmental effects for the plant.
- Using this information, the approach previously described for the ASME Code, Section III, Class 1 plants can be used to evaluate and manage fatigue environmental effects.

3.5 Consideration of Industry Operating Experience

Consistent with current practice, industry experience with fatigue cracking will continue to be reviewed. The assessment of any fatigue cracking in the extended operating period will consider the effects of environment as a potential contributor. Monitoring of industry experience must consider fatigue cracking for both anticipated and unanticipated transients. An MRP integrated fatigue management guideline is currently under preparation that will consider all aspects of fatigue management, including consideration of industry experience. See Reference [24].

4 GUIDANCE FOR PERFORMING ENVIRONMENTAL FATIGUE EVALUATIONS

This section provides guidance for performing plant specific environmental fatigue evaluations for selected locations. The intent is to unify the process used by applicants to address environmental effects in the License Renewal Application, and provide specific guidance on the use of currently accepted environmental fatigue evaluation methodologies.

There are several methods that have been published to assess the effects of reactor water environment on fatigue for each specific location to be considered. The currently accepted methodologies for evaluating environmental fatigue effects are documented in NUREG/CR-6583 [3] for carbon and low alloy steels and NUREG/CR-5704 [4] for austenitic stainless steels. Although other methods have been developed and published, guidance is only provided for using NUREG/CR-6583 [3] and NUREG/CR-5704 [4]. However, all methods currently published are similar in terms of variables and applicability (i.e., they all use an F_{en} factor approach), so the guidance that follows has general applicability to all methods. For reference, the other published methods, including those currently being used in Japan, are documented in References [18] and [22].

4.1 Environmental Fatigue Factor (F_{en}) Relationships

An environmental correction factor (F_{en}) is defined as the ratio of fatigue usage with environmental effects divided by fatigue usage in air, or allowable cycles to fatigue crack initiation in air divided by allowable cycles with water reactor environmental effects[1]. F_{en} equations are provided in the latest ANL reports for carbon and low alloy steel [3] and stainless steel [4].

From NUREG/CR-5704 [4], the F_{en} relative to room-temperature air for Types 304 and 316 stainless steel is given by the following expression:

$$F_{en} = \exp(0.935 - T^* \dot{\varepsilon}^* O^*)$$

The constants for transformed temperature (T^*), transformed strain rate ($\dot{\varepsilon}^*$), and transformed dissolved oxygen (O^*) in the above expression are defined as follows:

[1] "Fatigue crack initiation" is an investigator determined quantity, often related to a 25% load drop in a load-controlled laboratory fatigue test. This usually corresponds to significant crack depths, typically of the order of 25% of the specimen thickness for the deepest crack.

$T^* = 0$	($T < 200°C$)
$T^* = 1$	($T \geq 200°C$)
	T = metal service temperature, °C
$\dot{\varepsilon}^* = 0$	($\dot{\varepsilon} > 0.4\%$ /sec)
$\dot{\varepsilon}^* = \ell n(\dot{\varepsilon}/0.4)$	($0.0004 \leq \dot{\varepsilon} \leq 0.4\%$ /sec)
$\dot{\varepsilon}^* = \ell n(0.0004/0.4)$	($\dot{\varepsilon} < 0.0004\%$ /sec)
	$\dot{\varepsilon}$ = strain rate, %/sec
$O^* = 0.260$	(DO < 0.05 ppm)
$O^* = 0.172$	(DO ≥ 0.05 ppm)
	DO = dissolved oxygen

From NUREG/CR-6583 [3], the environmental correction factors relative to room-temperature air for carbon steel and alloy steel are given by the following expressions[2]:

<u>For carbon steel</u>: $F_{en} = \exp(0.585 - 0.00124\,T - 0.101 S^* T^* O^* \dot{\varepsilon}^*)$

Substituting T = 25°C to yield an F_{en} relative to room temperature air, the above equation becomes:

$$F_{en} = \exp(0.554 - 0.101 S^* T^* O^* \dot{\varepsilon}^*)$$

<u>For low alloy steel</u>: $F_{en} = \exp(0.929 - 0.00124\,T - 0.101 S^* T^* O^* \dot{\varepsilon}^*)$

Substituting T = 25°C to yield an F_{en} relative to room temperature air, the above equation becomes:

$$F_{en} = \exp(0.898 - 0.101 S^* T^* O^* \dot{\varepsilon}^*)$$

The transformed sulfur content (S^*), transformed temperature (T^*), transformed dissolved oxygen (O^*), and transformed strain rate ($\dot{\varepsilon}$ *) in the above expressions are defined as follows:

[2] It has been noted that several past license renewal applicants have substituted the maximum operating temperature for T in the second term of the F_{en} expressions (i.e., the " 0.00124 T" term) to represent the metal temperature. Since all ASME Code fatigue applications throughout the industry are based on relating room temperature air data to service temperature data in water, T = 25°C should be used in the F_{en} expressions for the "- 0.00124 T" term, rather than service temperature, as shown above.

$S^* = S$	$(0 < S \leq 0.015$ wt. %)
$S^* = 0.015$	$(S > 0.015$ wt. %)
	S = weight percent sulfur
$T^* = 0$	$(T < 150°C)$
$T^* = T - 150$	$(150 \leq T \leq 350°C)$
	T = metal service temperature, °C
$O^* = 0$	(DO < 0.05 ppm)
$O^* = \ell n\,(DO/0.04)$	(0.05 ppm $\leq$ DO $\leq$ 0.5 ppm)
$O^* = \ell n\,(12.5)$	(DO > 0.5 ppm)
	DO = dissolved oxygen
$\dot{\varepsilon}^* = 0$	$(\dot{\varepsilon} > 1\%/s)$
$\dot{\varepsilon}^* = \ell n\,(\dot{\varepsilon})$	$(0.001 \leq \dot{\varepsilon} \leq 1\%/s)$
$\dot{\varepsilon}^* = \ell n\,(0.001)$	$(\dot{\varepsilon} < 0.001\ \%/s)$
	$\dot{\varepsilon}$ = strain rate, %/sec

4.2 Guidelines for Application of the F_{en} Methodology

This section provides guidelines for performing environmental fatigue evaluations.

As introduced in Section 2.1, F_{en}s are determined and used to adjust the CUF previously determined using the ASME Code air curves. Bounding F_{en} values may be determined or, where necessary, individual F_{en} values are computed for each load pair in a detailed fatigue calculation. The environmental fatigue is then determined as $U_{env} = (U)\times(F_{en})$, where U is the original incremental fatigue usage for each load pair, and U_{env} is the environmentally assisted incremental fatigue usage factor. The total environmental CUF is computed as the sum of all U_{env} values for all load pairs.

Based on industry practice and recommendations available from some of the published F_{en} methods, there are three increasingly refined approaches used to compute the F_{en}s:

- Average strain rate
- Detailed strain rate
- Integrated strain rate

Common to each of these approaches is that the F_{en} is computed for the load pair over the increasing (tensile) portion of the paired stress range only. In other words, the relevant stress range is determined first by assuming that the transient with the maximum compressive stress (or minimum tensile stress) occurs first in time, followed by the transient with the maximum tensile stress. The relevant stress range for F_{en} computation is then from the maximum compressive stress (or minimum tensile stress) to the maximum tensile stress. Further details are given in the discussions that follow.

A separate section follows for each parameter utilized in the F_{en} expressions, that is transformed sulfur content (S^*), transformed temperature (T^*), transformed dissolved oxygen (O^*), and transformed strain rate ($\dot{\varepsilon}^*$). For the transformed strain rate, temperature, and oxygen parameters, the three approaches are discussed. Transformed sulfur does not vary over the three approaches. A single approach should be utilized for all of the transformed parameters in a single load-pair F_{en} determination, although different approaches may be utilized for different load-pair F_{en}s.

First, the typical content of a fatigue calculation is presented.

4.2.1 Contents of a Typical Fatigue Evaluation

This section provides the content of a typical fatigue calculation. Whereas fatigue calculations have varied over the years, their basic content is the same. With the advent of computer technology, the calculations have basically maintained the same content, but computations have become more refined and exhaustive. For example, 30 years ago it was computationally difficult for a stress analyst to evaluate 100 different transients in a fatigue calculation. Therefore, the analyst would have grouped the transients into as few as one transient grouping and performed as few incremental fatigue calculations as possible. With today's computer technology and desire to show more margin, it is relatively easy for the modern-day analyst to evaluate all 100 incremental fatigue calculations for this same problem. Also, older technology would have likely utilized conservative shell interaction hand solutions for computing stress, whereas today finite element techniques are commonly deployed. This improvement in technology would not have changed the basic inputs to the fatigue calculation (i.e., stress), but it would have typically yielded significantly more representative input values.

The discussion here is limited to the general content of most typical fatigue calculations. Discussions of removing excess conservatisms from the input (stress) values of these calculations are not included, as it is assumed that those techniques are generally well understood by engineers performing these assessments throughout the industry.

Two typical fatigue calculations are shown in Figures 4-1 through 4-4. Figure 4-1 reflects an "old" calculation, i.e., one that is typical from a stress report from a plant designed in the 1960s. Figures 4-2 through 4-4 reflect a "new" calculation, i.e., one that is typical from a 1990s vintage stress report. A description of the content of these two calculations is provided below.

The same basic content is readily apparent in both CUF calculations shown in Figures 4-1 through 4-4. However, it is also apparent that much more detail is present in Figures 4-2 through 4-4 for the "new" calculation compared to Figure 4-1 for the "old" calculation. Therefore, with respect to applying F_{en} methodology to a CUF calculation, the guidance provided in the following sections equally applies to both vintages of calculations. The main difference is in assumptions that need to be made for the F_{en} transformed variables due to a lack of detail backing up the calculations in the stress report. Guidance for these assumptions is described in Sections 4.2.2 through 4.2.5, with appropriate reference to the calculations shown in Figures 4-1 through 4-4.

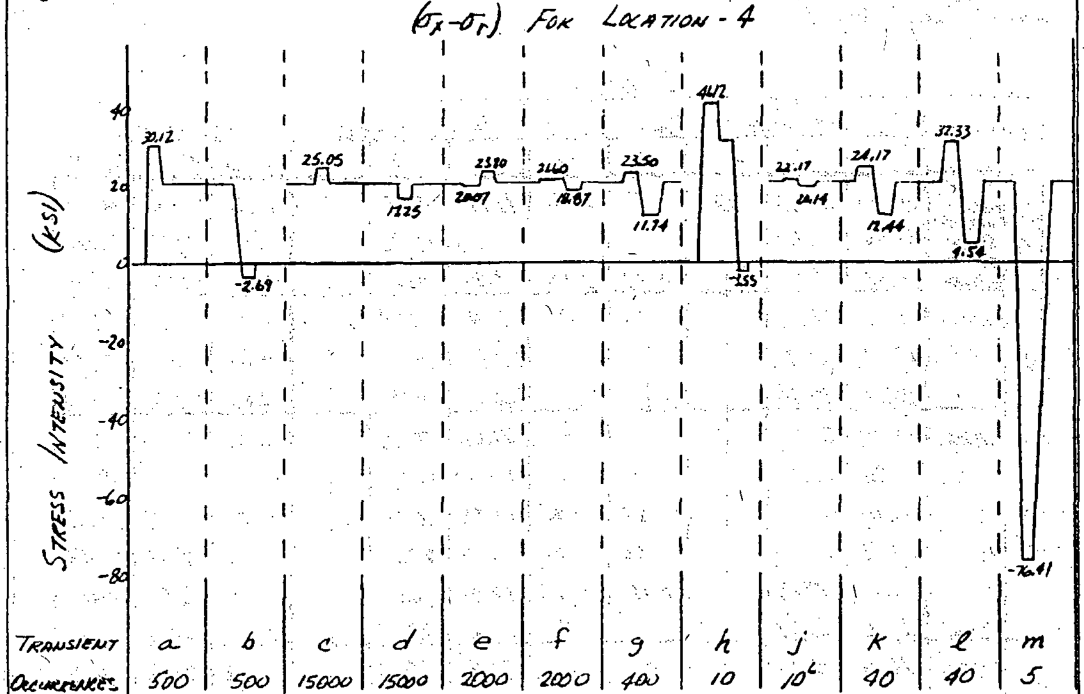
4.2.1.1 "Old" Calculation (Figure 4-1)

The following describes the basic contents of the CUF calculation shown in Figure 4-1. Note that this calculation is an NB-3200-style (vessel) CUF calculation. Reference is made to the heading and the first line in the table shown at the bottom of Figure 4-1.

S_{MAX}	=	maximum stress intensity for transient pair (ksi). For this example, it is seen that it represents the tensile stress for Transient "h" in the stress histogram above the CUF calculation table.
S_{MIN}	=	minimum stress intensity for transient pair (ksi). For this example, it is seen that it represents the compressive stress for Transient "m" in the stress histogram above the CUF calculation table.
S_{ALT}	=	alternating stress intensity (ksi). This is computed as $0.5(S_{MAX} - S_{MIN})$. It is noteworthy that K_e and Young's Modulus corrections are not included in this calculation due to the early ASME Code edition used for the evaluation.
n	=	number of applied cycles for transient pair. For this example, it is seen that this value represents the limiting number of occurrences for the paired transients (i.e., Transients "h" and "m"), which is 5 cycles from the stress histogram above the CUF calculation table. The occurrences of Transient "m" are now exhausted, and 5 cycles of Transient "h" remain for use in the remaining CUF calculation.
N	=	allowable number of cycles from the applicable ASME Code fatigue curve for the material under consideration for S_{ALT}. From the "*" note, ASME Code Figure N-415(a) applies (1960s ASME Code edition).
u	=	incremental CUF for the load pair, computed as n/N.
$U_{OVERALL}$	=	total CUF for this location for the design life of the component, computed as Σu.

5- DETAILED ANALYSIS:

9- FATIGUE EVALUATION:



S_{MAX}	S_{MIN}	S_{ALT}	n	N*	u
41.12	-76.41	58.76	5	1860	0.00269
41.12	-3.55	22.34	5	40020	0.00013
32.33	-2.69	17.51	40	95650	0.00042
30.12	-2.69	16.41	460	133000	0.00346
25.05	11.74	6.65	400	∞	0

*FROM FIG. N-415(A) OF REFERENCE -1

$U_{OVERALL} = 0.0067$

Figure 4-1
Example of "Old" Fatigue Calculation

4.2.1.2 "New" Calculation (Figures 4-2 through 4-4)

The following describes the basic contents of the CUF calculation shown in Figure 4-2. Note that this calculation is an NB-3600-style (piping) CUF calculation. References are also made to Figures 4-3 and 4-4 where necessary.

(Note: Near the top of the table shown in Figure 4-2, the maximum load case information is reported, i.e., the two lines beginning with "GELBOW" and "0.512" – the descriptions that follow apply to the information below these lines.)

Load Range	=	paired load cases, as defined in Load Case definitions (see Figure 4-3).
Equation 10 Moment	=	moment (ft-lbf), computed in accordance with Equation (10) of ASME Code, Section III, NB-3600.
Equation 10 Stress	=	stress intensity (psi), computed in accordance with Equation (10) of ASME Code, Section III, NB-3600.
Equation 11 Moment	=	moment (ft-lbf), computed in accordance with Equation (11) of ASME Code, Section III, NB-3600.
Equation 11 Stress	=	stress intensity (psi), computed in accordance with Equation (11) of ASME Code, Section III, NB-3600.
Equation 12 Moment	=	moment (ft-lbf), computed in accordance with Equation (12) of ASME Code, Section III, NB-3600.
Equation 12 Stress	=	stress intensity (psi), computed in accordance with Equation (12) of ASME Code, Section III, NB-3600.
Equation 13 Moment	=	moment (ft-lbf), computed in accordance with Equation (13) of ASME Code, Section III, NB-3600.
Equation 13 Stress	=	stress intensity (psi), computed in accordance with Equation (13) of ASME Code, Section III, NB-3600.
Equation 14 KE	=	elastic-plastic strain concentration factor, K_e, computed in accordance with ASME Code, Section III, NB-3600.
Equation 14 Stress	=	alternating stress intensity (psi), computed in accordance with Equation (14) of ASME Code, Section III, NB-3600.
Cycles Actual	=	number of applied cycles for the transient pair. For this example, the first load pair represents thermal Load Cases 24 and 36, coupled with dynamic Load Case 56 and (E)arthquake. From Figure 4-3, Load Case 24 represents Daily Power Reduction, Load Case 36 represents Vessel Flooding, and Load Case 56 represents OBE/SRV

dynamic loading. From the transient definitions (similar to those shown in Figure 4-4), the number of applied cycles for each load case is obtained. The fatigue analysis uses the limiting number of cycles for all of these loads, which is 10 cycles.

Cycles Allow = allowable number of cycles from the applicable ASME Code fatigue curve for the material under consideration for "Equation 14 Stress".

Usage Factor = incremental CUF for the load pair, computed as "Cycles Actual"/"Cycles Allow".

The total CUF for this location for the design life of the component, computed as Σu, is shown at the top of the table in the summary portion (i.e., 0.6512).

ASME SECTION III CLASS 1 (W/O) MEMBER STRESS SUMMARY

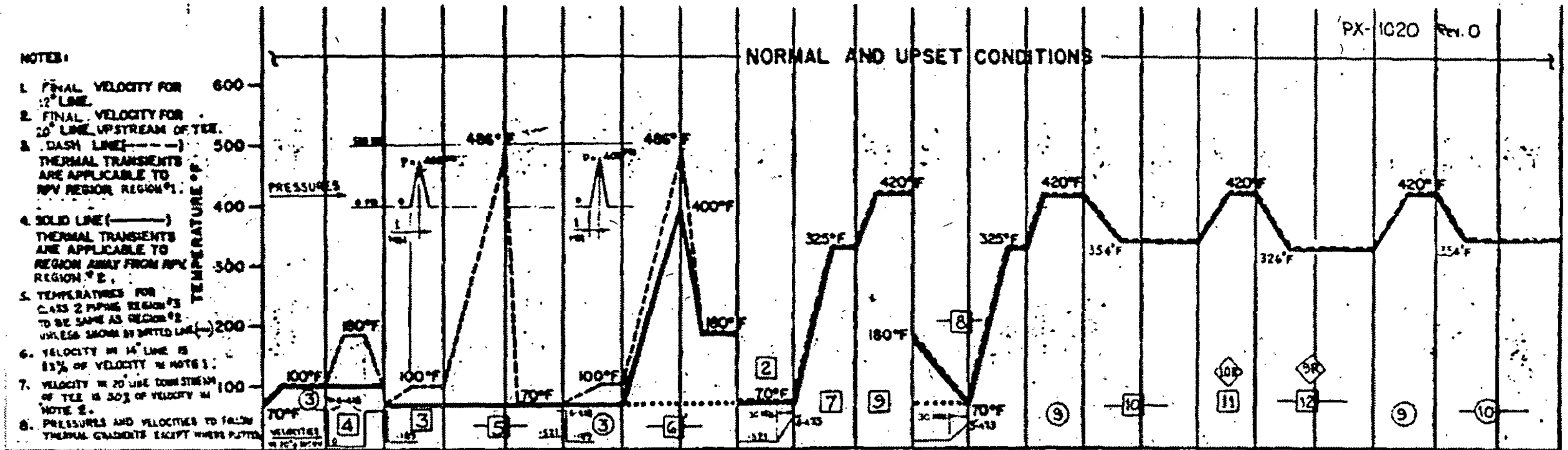
UNITS - MIN WALL(IN), MOMENTS(FT-LBF), AND STRESS (PSI)

MEMBER/ MIN WALL	END/ EQ.9	LOAD RANGE	EQUATION 10 MOMENT	EQUATION 10 STRESS	EQUATION 11 MOMENT	EQUATION 11 STRESS	EQUATION 12 MOMENT	EQUATION 12 STRESS	EQUATION 13 MOMENT	EQUATION 13 STRESS	EQUATION 14 KE	EQUATION 14 STRESS	CYCLES ACTUAL	CYCLES ALLOW	USAGE FACTOR
GELBOW 0.512	85 16056 (56)	MAXIMUM	143173	77836*	143173	132028	114270	46162	16721	24073	1.62	107166			0.6512
			(E,56,24-36)		(E,56,24-36)			(24-36)	(E,56,35-43)		(E,56,24-36)				
		(E,56,24-36)	143173	77836	143173	132028	114270	46162	16721	21777	1.62	107166	10	494	0.0202
		(E,56,24-27)	142334	75954	142334	130901	113390	45806	16721	18521	1.58	103510	30	542	0.0553
		(E,56,23-24)	137776	74542	137776	127991	108817	43958	16721	19093	1.51	96785	60	650	0.0923
		(56,23-24)	137776	74542	120986	115782	108817	43958	16721	19093	1.28	74319	10	1351	0.0074
		(56,20-24)	137776	72778	120986	112284	108817	43958	16721	19093	1.22	68736	90	1689	0.0533
		(56,30-43)	133983	70332	117164	110055	104930	42389	16721	16077	1.12	61516	1	2335	0.0004
		(56,20-42)	137567	68279	120789	103190	108643	43888	16721	19321	1.07	55353	632	3200	0.1975
		(56,30-44)	133983	66436	117164	105380	104930	42389	16721	12181	1.00	52690	14	3716	0.0038
		(56,15-44)	134852	65752	118061	103094	105894	42778	16721	13323	1.00	51547	15	3974	0.0038
		(56,20-44)	137776	61297	120986	98507	108817	43958	16721	7611	1.00	49254	161	4572	0.0352
		(56,20-41)	122192	62268	105571	93599	93733	37865	16721	17950	1.00	46799	10	5361	0.0019
		(56,20-37)	100145	60316	84455	91572	73932	29866	16721	19093	1.00	45786	1	5743	0.0002
		(56,20-26)	137499	57445	120722	91111	108578	43862	16721	7326	1.00	45555	111	5835	0.0190
		(56,11-20)	137567	56712	120789	88110	108643	43888	16721	6756	1.00	44055	370	6488	0.0570
		(55,11-20)	136226	55171	117210	85508	108643	43888	16721	6755	1.00	42754	72	7139	0.0101
		(55,20-38)	136226	55171	117210	85508	108643	43888	16721	6755	1.00	42754	106	7139	0.0148
		(55,20-40)	107472	57662	88478	84563	79998	32317	16721	17036	1.00	42282	15	7398	0.0020
		(55,20-29)	110898	54134	91830	81742	83254	33632	16721	11324	1.00	40871	15	8254	0.0018
		(55,20-34)	97950	53643	80683	77208	73612	29737	16721	18760	1.00	38604	15	9943	0.0015
		(55,14-20)	112804	51421	93769	75317	85239	34434	16721	12467	1.00	37659	106	10791	0.0098
		(55,33-39)	82611	50218	65317	71649	57620	23236	16721	18750	1.00	35824	15	12743	0.0012
		(55,28-33)	80006	49222	62982	70438	55299	22339	16721	18179	1.00	35219	15	13494	0.0011
		(55,20-32)	82304	47036	66291	66163	60256	24342	16721	18750	1.00	33082	126	16692	0.0075
		(55,25-33)	83526	47061	66483	65820	58760	23737	16721	18179	1.00	32910	111	16992	0.0065
		(55,20-36)	84439	46865	68288	65110	62130	25098	16721	19321	1.00	32655	249	17637	0.0141
		(55,10-31)	73389	44115	57180	60909	51152	20664	16721	18750	1.00	30455	111	22238	0.0050
		(55,12-20)	83180	41690	65876	57581	58845	23771	16721	14751	1.00	28840	485	26955	0.0180
		(55,10-33)	72338	42870	54844	57561	47811	19314	16721	18750	1.00	28780	66	27166	0.0024
		(55,13-20)	79803	34091	63810	48735	57832	23362	16721	8468	1.00	24367	40	50001	0.0008
		(55,10-16)	58920	27787	39612	36710	30996	12521	16721	6755	1.00	18355	307	153686	0.0020
		(55,10-17)	58920	27769	39612	36676	30996	12521	16721	6755	1.00	18338	15	154462	0.0001
		(55,20-22)	59302	27302	40000	34705	31396	12683	16721	8057	1.00	17353	70	195284	0.0004
		(55,20-21)	58022	24124	38710	29175	30104	12161	16721	7177	1.00	14587	2000	424557	0.0047
		(55,19-20)	57005	23559	29713	22466	21094	8521	16721	7006	1.00	11233	4310	999999	0.0000

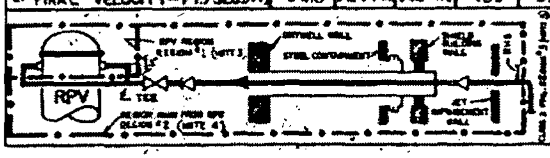
Figure 4-2
Example of "New" Fatigue Calculation – CUF Calculation

LOAD CASE NUMBER	DESCRIPTION
	Normal/upset condition (Run 004)
1	FT= FLUID TRANSIENT TIME HISTORY (3-PUMP-TRIP)
2	OBEI= OBE INERTIA.....GROUPING BY STD SRSS
3	SSEI= SSE INERTIA.....GROUPING BY STD SRSS
4	SRV (1V,2V,SRVCO2V)..........GROUPING BY STD SRSS
5	SRV (16V,SRVCO16V)...........GROUPING BY STD SRSS
6	COCH= CONDENS.OSCILL & CHUGGING........GROUPING BY STD SRSS
7	PS= POOL SWELL...............GROUPING BY STD SRSS
8	APMSB= ANNULUS PRESSURIZATION M.S.B... GROUPING BY STD SRSS
9	APRCB= ANNULUS PRESSURIZATION R.C.B....GROUPING BY STD SRSS
10	APFWB= ANNULUS PRESSURIZATION F.W.B....GROUPING BY STD SRSS
11	DL= DEADWEIGHT ANALYSIS: TLOAD=3,(F@5H = COLDSET LOAD)
12	X-DIR OBE ANCHOR MVMTS
13	Y-DIR OBE ANCHOR MVMTS
14	Z-DIR OBE ANCHOR MVMTS
15	THERM 1= NORMAL OPERATING: (12) PPG @ 420/420/420 F RPV @ 552/528/528
16	THERM 2= TURB ROLL COLD: (4A-1..) PPG @ 70/70/70 F RPV @ 552/552/450
17	THERM 3= BOLT-UP,LEAK TEST: (3A-1..) 70-100
18	THERM 4= HYDROTEST: (2A) 100-180-100
19	THERM 5= START-UP:{UP} (3A-2..) 100-486
20	THERM 6= START-UP:{UP} (3B-2) 100-486
21	THERM 7= TURB ROLL: (4A-2..) 70-325
22	THERM 8= TURB ROLL: (4B-1+2) 180-70-325
23	THERM 9= TURB ROLL: (4A-3..) 325-420
24	THERM 10= DAILY PWR REDCTN : (5-1+2..) 420-354
25	THERM 11= DAILY PWR INCR : (5-3..) 354-420
26	THERM 12= WEEKLY PWR REDCTN : (6-1+2) 420-326
27	THERM 13= FW HTR LOSS: (9-1+2) 420-352
28	THERM 14= FW HTR RESTORTN: (9-3) 352-420
29	THERM 15= SCRAMS: (22-1+2..) 420-275
30	THERM 16= PWR REDUCTN: (13) 420-190
31	THERM 17= HOT STDBY: (14A) 190-70
32	THERM 18= HOT STDBY: (14B-1..) 190-435
33	THERM 19= HOT STDBY: (14B-2) 435-190
34	THERM 20= SHUT-DOWN INITIATN: (15B-1) 435-156
35	THERM 21= SHUT-DOWN INITITN:{UP} (15B-2) 156-395
36	THERM 22= VESSEL FLOODING: (16A-1) 70-157
37	THERM 23= VESSEL FLOODING: (16A-3..) 167-108
38	THERM 24= VESSEL FLOODING: (16A-4..) 108-167
39	THERM 25= VESSEL FLOODING: (16B-1+2) 149-66-152
40	THERM 26= SHUT-DOWN, UNBOLT: (17A..) 167-100
41	THERM 27= LOSS OF FW PUMP:{UP} (20-1..) 420-573-485
42	THERM 28= PIPE RUPTURE: (27-1+2) 420-259-70
43	THERM 29= START-UP:{DN} (3A-3..) 486-70
44	THERM 30= START-UP:{DN} (3B-3) 486-180
45	THERM 31= SHUT-DOWN INITITN:{DN} (15B-3) 395-149
46	THERM 32= LOSS OF FWP:{DN} (20-13+14) 485-70
47	THERM 33= TMODE 2 WITH P=0 PSI
48	THERM 34= TMODE 15 WITH P=1516 PSI
49	THERM 35= TMODE 15 WITH P=1175 PSI
50	X+Y DIR. OBE ANCHOR MVMTS..........CASES 12+13 BY SRSS
51	OBEA= X+Y+Z EARTHQUAKE ANCHOR MVMTS....CASES 12+13+14 BY SRSS
52	SRV= (SRV MAX).............CASES 4+5 BY MAXIMUM VALUE
53	SRSS(SRV,FT)..............CASES 52+1 BY SRSS
54	SRSS(OBEI,OCCU)= SRSS(OBEI,SRV,FT)...CASES 2+52+1 BY SRSS
55	OBET= ABS(OBEI + OBEA).....CASES 2+51 BY ABS. SUM
56	SRSS(OBET,OCCU)= SRSS(ABS(OBEI+OBEA),SRV,FT)..CASES55+53 BY SRSS
57	SRSS(OBEI,FT)..............CASES 1+2 BY SRSS (FOR 9CN CARD ONLY)
58	FT= FLUID TRANSIENT TIME HISTORY(3 PUMP-TRIP)....(FOR SUMMARY ONLY)
59	OBEI= OBE INERTIA (CASE REPEATED FOR SUMMARY ONLY)
60	SRV(1V,2V,SRVCO2V)..........(CASE REPEATED FOR 9N CARD ONLY)
61	SRV(16V.SRVCO16V).......... (CASE REPEATED FOR 9N CARD ONLY)
	(RUN 007)
1	SETTLE1 = BLDG. SETTLEMENT ... REACTOR BLDG. SETTLES DOWN BY .66".
2	SETTLE2 = BLDG. SETTLEMENT ... AUX. BLDG. SETTLES DOWN BY .18".

Figure 4-3
Example of "New" Fatigue Calculation – Load Pair Definitions



EVENT DESCRIPTION	BOLT-UP	DESIGN HYDRO TEST	START-UP LEAK CHECKS	START-UP RPV HEAT-UP	START-UP RFP FLOW	START-UP RPV LEAK CHECKS	START-UP RPV-RHCU HEAT-UP	START RFP FLOW	TURBINE ROLL: INCREASE FWS FLOW	TURBINE ROLL: START FWS HEATERS	TURBINE ROLL: RAISE FWS FLOW/TEMP	TURBINE ROLL: INCREASE FWS FLOW	TURBINE ROLL: START FWS HTRS	TURBINE ROLL: RAISE FWS FLOW/TEMP	DAILY POWER REDUCTION: DECREASE POWER	DAILY POWER REDUCTION: HOLD PERIOD	DAILY POWER REDUCTION: INCREASE POWER	WEEKLY POWER REDUCTION: DECREASE POWER	WEEKLY POWER REDUCTION: HOLD PERIOD	WEEKLY POWER REDUCTION: INCREASE POWER	ROD PATTERN CHNG: DECREASE POWER	ROD PATTERN CHNG: HOLD PERIOD
EVENT NUMBER	1	2A	3A-1	3A-2	3A-3	3B-1	3B-2	3B-3	4A-1	4A-2	4A-3	4B-1	4B-2	4B-3	5-1	5-2	5-3	6-1	6-2	6-3	7-1	7-2
PRESSURE - PSIG	0	[illegible]	0-400-0	0-600	600-1100	0-400-0	0-600	600-1100	1100-1100	1100-1100	1100-1100	1100-1100	1100-1100	1100-1100	1100-1078	1078	1078-1100	1100-1063	1063	1063-1100	1100-1078	1078
DURATION OF FINAL TEMP - HR.	INDEF	INDEF.	INDEF.	INDEF.	INDEF.	INDEF.	0	INDEF.	INDEF	0.1667	INDEF.	0	0.1667	INDEF.	INDEF.	INDEF	INDEF.	INDEF.	INDEF	INDEF.	INDEF.	INDEF
NO. OF CYCLES	123	40	315	108	108	45	15	15	108	108	108	15	15	15	10,000	10,000	10,000	2000	2000	2000	400	400
RATE OF TEMP. CHANGE - °F/HR.	≤ 100	≤ 100	≤ 100	≤ 100	-14,560	≤ 100	≤ 100	-18,345 -15,720	0	7650	190	-6600	7650	190	-264	0	264	-188	0	188	-264	0
TIME - SEC. FOR ΔTEMP.	1080	2880	1080	13,896	60	1080	13,896 11,880	60 60	—	120	1800	60	120	1800	900	—	900	1800	—	1800	900	—
1. FINAL VELOCITY - FT./SEC.(1)	7.38	[illegible]	.238-.234	.235	.648	.238-.234	.236	.666	[illegible]	7.517	24.342	[illegible]	7.517	24.342	17.393	17.393	24.342	12.223	12.223	24.342	17.393	17.393
2. FINAL VELOCITY - FT./SEC.(2)	6.418	[illegible]	6.418-.185	.189	.521	6.418-.185	.189	.536	.521-5.473	6.043	19.568	.536-5.473	6.043	19.568	13.982	13.982	19.568	9.143	9.143	19.568	13.982	13.982



REFERENCES:
1. CALCULATION 227.700-001 BY R.J. Mc MORLAND
2. PTP 26-1-15-0 FEED WATER SYSTEM (FSK-6-1/EP17) TRANSIENT DATA SHEETS ATTACHMENT 'A', PICL NO. AP-17 DATED 2-10-84.

Controlling Trans.

Identical cases, temp. reversed.

Trans already considered enveloped.

PREPARED BY	[signature]	3-16-84
CHECKED BY	[signature]	3-16-84
REVIEWED BY	[signature]	3-14-84
REVIEWED BY	[signature]	3-28-84
APPROVED BY	[signature]	4-3-84
DATE OF ISSUE		
SHEET 1 OF 5		

THERMAL TRANSIENTS
FEEDWATER SYSTEM (FWS)

STONE & WEBSTER ENGINEERING CORPORATION

12210-SK-TR17-A-1

Figure 4-4
Example of "New" Fatigue Calculation – Transient Definitions

4.2.2 Transformed Strain Rate, $\dot{\varepsilon}$ *

The transformed strain rate, $\dot{\varepsilon}^*$, is required by both the carbon and low alloy steel F_{en} expressions documented in NUREG/CR-6583 [3], and the stainless steel F_{en} expression documented in NUREG/CR-5704 [4], and is defined as follows:

For carbon/low alloy steels (NUREG/CR-6583 [3]):

$$\dot{\varepsilon}^* = 0 \qquad (\dot{\varepsilon} > 1\%/\text{s})$$

$$\dot{\varepsilon}^* = \ell n(\dot{\varepsilon}) \qquad (0.001 \le \dot{\varepsilon} \le 1\%/\text{s})$$

$$\dot{\varepsilon}^* = \ell n(0.001) \qquad (\dot{\varepsilon} < 0.001\ \%/\text{s})$$

$\dot{\varepsilon}$ = strain rate, %/sec

For stainless steels (NUREG/CR-5704 [4]):

$$\dot{\varepsilon}^* = 0 \qquad (\dot{\varepsilon} > 0.4\%\ /\text{sec})$$

$$\dot{\varepsilon}^* = \ell n(\dot{\varepsilon}/0.4) \qquad (0.0004 \le \dot{\varepsilon} \le 0.4\%\ /\text{sec})$$

$$\dot{\varepsilon}^* = \ell n(0.0004/0.4) \qquad (\dot{\varepsilon} < 0.0004\%\ /\text{sec})$$

$\dot{\varepsilon}$ = strain rate, %/sec

The above expressions are straightforward to apply if the strain rate, $\dot{\varepsilon}$, is known. This can be relatively straightforward for design transients where definitive ramp rates and temperature differentials are provided. It is much more difficult for actual transients obtained from actual plant data or fatigue monitoring systems. In particular, how two transients that occur separately in time are "linked" together (as shown in Figure 4-9) can have a significant influence on strain rate calculations depending upon the method used.

Section 4.3 discusses other issues associated with calculating the strain rate when applying the F_{en} expressions. Solving those other issues is beyond the scope of this report, so guidance is provided in this section to address only the above three methods of computing strain rate.

Consistent with some of the calculations performed in NUREG/CR-6260 [2], for cases where the magnitudes of the portions of the stress range due to heatup and cooldown are unknown (i.e., only the total stress intensity range is known), or for cases where the stress histories are not available, one-half of the alternating stress intensity may be used to compute strain rate. This is done in the sample problem shown in Section 4.2.7, but it requires that some form of time history information be available for the transient to justify strain rates greater than the slowest saturated strain rate. Parametric studies could also be used to justify time assumptions.

Discussion for each of the three Average, Detailed, and Integrated Strain Rate approaches follows.

Approach #1: Average Strain Rate

The Average Strain Rate approach is simple in that it is based on "connecting the valley with the peak with a straight line and computing the slope." Referring to Figure 4-9, this represents the slope of a line drawn from the lowest stress point of the heatup (maximum compressive) event (i.e., left side of Figure 4-9), to the highest stress point of the cooldown (maximum tensile) event (i.e., right side of Figure 4-9). But, as shown in the area between the two events in Figure 4-9, linking of the two transients is not necessarily straightforward. There are two issues associated with the proper linking of the two events:

- For the maximum compressive stress transient (i.e., left side of Figure 4-9), the return (tensile) side of the transient is important for the strain rate calculation. An estimate of the time until steady state conditions are reached is needed.
- The ending stress for the maximum compressive stress transient (i.e., left side of Figure 4-9) may be different than the beginning stress for the maximum tensile stress transient (i.e., right side of Figure 4-9). This difference causes a discontinuity in the linking process.

The following guidance is provided for each of the above issues:

- For steady state conditions associated with the return (tensile) side of the maximum compressive stress transient, the time for the stress to reach at least 90% of the steady state stress value can be used. This involves a steady state stress solution that includes a time-based solution, which is readily available in most stress analyses, and is readily achievable with the use of all modern-day stress programs.
- For stress discontinuities that exist between the ending stress for the maximum compressive stress transient and the beginning stress for the maximum tensile stress transient, the transients can be linked with a vertical line between the two stress points (i.e., no elapsed time).

Under the above assumptions, the Average Strain Rate is computed as:

$$\dot{\varepsilon} = 100\Delta\sigma/(\Delta tE)$$

where: $\dot{\varepsilon}$ = average strain rate, %/sec

$\Delta\sigma$ = total stress intensity range

= stress difference between the highest stress point of the maximum tensile stress event (i.e., right side of Figure 4-9) and the lowest stress point of the maximum compressive stress event (i.e., left side of Figure 4-9), psi

Δt = time between peak and valley, sec

	=	time lapse from the event start to the algebraic highest stress point of the maximum tensile stress event (i.e., right side of Figure 4-9) plus the time lapse from the algebraic lowest stress point of the maximum compressive stress event (i.e., left side of Figure 4-9), to the time for the stress to reach at least 90% of the steady state stress value, sec.
E	=	Young's Modulus, psi, normally taken from the governing fatigue curve used for the fatigue evaluation.

Approach #2: Detailed Strain Rate

The Detailed Strain Rate approach is similar to the average approach discussed above, except that a weighted strain rate is obtained based on strain-based integration over the increasing (tensile) portion of the paired stress range. Referring to Figure 4-9, this represents the integrated slope of strain response from the algebraic lowest stress point of the maximum compressive stress event to the algebraic highest stress point of the maximum tensile stress event, weighted by strain. Similar to the average approach discussed above, linking of the two transients in not necessarily straightforward. However, the two issues associated with the proper linking of the two events that are identified above are less pronounced because of the integration process. Nevertheless, aspects of these issues remain, so the following guidance is provided for each of those issues:

- For steady state conditions associated with the return (tensile) side of the maximum compressive stress transient, the time for the stress to reach at least 90% of the steady state stress value can be used. This involves a steady state stress solution, which is readily available in most stress analyses, and is readily achievable with the use of all modern-day stress programs.
- For stress discontinuities that exist between the ending stress for the maximum compressive stress transient and the beginning stress for the maximum tensile stress transient, the discontinuity can be ignored.

Under the above assumptions and referring to Figure 4-5, the Detailed Strain Rate is computed as:

$$\dot{\varepsilon} = \frac{100 \sum \Delta\varepsilon_i \dfrac{\Delta\varepsilon_i}{\Delta t}}{\sum \Delta\varepsilon_i}$$

where: $\dot{\varepsilon}$	=	detailed strain rate, %/sec
$\Delta\varepsilon_i$	=	change in strain at Point i, in/in
	=	$(\sigma_i - \sigma_{i-1})/E$
σ_i	=	stress intensity at Point i, psi
σ_{i-1}	=	stress intensity at Point i-1, psi
Δt	=	change in time at Point i, sec
	=	$t_i - t_{i-1}$
E	=	Young's Modulus, psi, normally taken from the governing fatigue curve used for the fatigue evaluation.

The summation is over the range from Point (3) to (4) and the range from Point (1) to (2). In the figure, Points (1) and (4) are assumed coincident. Point (4) is actually taken as the point where the stress returns to at least 90% of the steady state stress value. The strain discontinuity between this point and Point (1) is accounted for by omitting this increment from the total strain range in the denominator.

If two tensile transients are being ranged, the summation ranges from the algebraic minimum of the two Point (1)s to the algebraic maximum of the two Point (2)s. If two compressive transients are being ranged, the summation ranges from the algebraic minimum of the two Point (3)s to the algebraic maximum of the two Point (4)s. If a tensile transient is being ranged with itself (its 'zero' state), the summation ranges from Point (1) to Point (2). If a compressive transient is being ranged with itself (its 'zero' state), the summation ranges from Point (3) to Point (4) with Point (4) again taken where the stress returns to at least 90% of the steady state stress value.

<u>Approach #3: Integrated Strain Rate</u>

The Integrated Strain Rate approach is similar to the detailed approach discussed above, except that an F_{en} factor is computed at multiple points over the increasing (tensile) portion of the paired strain range, and an overall F_{en} is integrated over the entire tensile portion of the strain range (i.e., from the algebraic lowest stress point of the maximum compressive stress event to the algebraic highest stress point of the maximum tensile stress event in Figure 4-9). Thus, this process is more specifically an "integrated F_{en} approach", where strain rate is computed as a part of the process. Similar to the two approaches discussed above, linking of the two transients remains an issue with this method. However, similar to the detailed approach, the two issues associated with the proper linking of the two events are less pronounced because of the integration process. The following guidance is provided for each of those issues:

- For steady state conditions associated with the return (tensile) side of the maximum compressive stress transient, the time for the stress to reach at least 90% of the steady state stress value can be used. This involves a steady state stress solution, which is readily available in most stress analyses, and is readily achievable with the use of all modern-day stress programs.
- For stress discontinuities that exist between the ending stress for the maximum compressive stress transient and the beginning stress for the maximum tensile stress transient, the discontinuity can be ignored.

Under the above assumptions and referring to Figure 4-5, the Integrated Strain Rate F_{en} is computed as:

$$F_{en} = \frac{\sum F_{en,i} \Delta\varepsilon_i}{\sum \Delta\varepsilon_i}$$

where: $F_{en,i}$ = F_{en} computed at Point i, based on $\dot{\varepsilon}_i = 100\Delta\varepsilon_i/\Delta t$ and transformed parameters (T^*) and (O^*) computed using the respective Integrated Strain Rate approaches for each, discussed below.

$\Delta\varepsilon_i$ = change in strain at Point i, in/in

= $(\sigma_i - \sigma_{i-1})/E$

σ_i	=	stress intensity at Point i, psi
σ_{i-1}	=	stress intensity at Point i-1, psi
Δt	=	change in time at Point i, sec
	=	$t_i - t_{i-1}$
E	=	Young's Modulus, psi, normally taken from the governing fatigue curve used for the fatigue evaluation.

The summation is over the range from Point (3) to (4) and the range from Point (1) to (2). In the figure, Points (1) and (4) are assumed coincident. Point (4) is actually taken as the point where the stress returns to at least 90% of the steady state stress value. The strain discontinuity between this point and Point (1) is accounted for by omitting this increment from the total strain range in the denominator.

If two tensile transients are being ranged, the summation ranges from the algebraic minimum of the two Point (1)s to the algebraic maximum of the two Point (2)s. If two compressive transients are being ranged, the summation ranges from the algebraic minimum of the two Point (3)s to the algebraic maximum of the two Point (4)s. If a tensile transient is being ranged with itself (its 'zero' state), the summation ranges from Point (1) to Point (2). If a compressive transient is being ranged with itself (its 'zero' state), the summation ranges from Point (3) to Point (4) with Point (4) again taken where the stress returns to at least 90% of the steady state stress value.

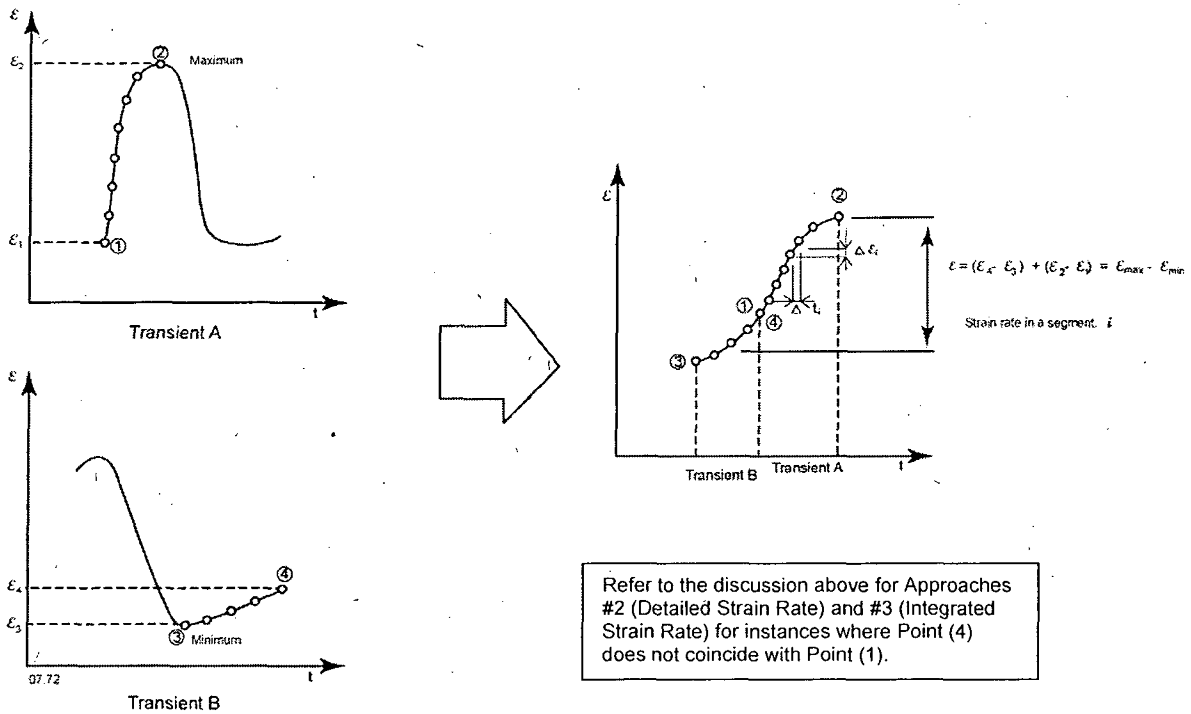


Figure 4-5
Detailed and Integrated Strain Rate Calculation

4.2.3 Transformed Sulfur Content, S*

The transformed sulfur content, S*, is required only by the carbon and low alloy steel F_{en} expressions documented in NUREG/CR-6583 [3], and is defined as follows:

$S^* = S$ $(0 < S \leq 0.015 \text{ wt. \%})$

$S^* = 0.015$ $(S > 0.015 \text{ wt. \%})$

S = weight percent sulfur

There are no ambiguities associated with computing S*, as it is a function of the material sulfur content for the location under consideration. Normally, sulfur content would be obtained from Certified Material Test Reports (CMTRs) that are usually readily available. However, due to the secondary effect of this variable in the F_{en} expressions, most analyses to-date have assumed high sulfur content (i.e., S* = 0.015) for simplicity.

4.2.4 Transformed Temperature, T*

The transformed temperature, T*, is required by both the carbon and low alloy steel F_{en} expressions documented in NUREG/CR-6583 [3], and the stainless steel F_{en} expression documented in NUREG/CR-5704 [4], and is defined as follows:

For carbon/low alloy steels (NUREG/CR-6583 [3]):

$T^* = 0$ $(T < 150°C)$

$T^* = T - 150$ $(150 \leq T \leq 350°C)$

T = metal service temperature, °C

For stainless steels (NUREG/CR-5704 [4]):

$T^* = 0$ $(T < 200°C)$

$T^* = 1$ $(T \geq 200°C)$

T = metal service temperature, °C

The above expressions are straightforward to apply if the metal service temperature, T, is known.

As discussed in Section 4.3, there are other issues associated with temperature when applying the F_{en} expressions. Generally, the issue is, "what temperature should be used for the general transient pairing shown in Figure 4-9?" The answer to this question is dependent upon the refinement on the evaluation used to compute the F_{en} factor. As discussed above at the start of Section 4.2, there are three increasingly refined approaches used to compute the F_{en} factor: Average, Detailed, and Integrated Strain Rate.

The following recommendations are made for determining the temperature, T, for each of the above three approaches:

Approach #1: F_{en} Factor Calculated Based on Average Strain Rate Calculation

For this approach, a constant temperature that is the maximum of the fluid temperatures of both paired transients over the time period of increasing tensile stress should be used. Referring to Figure 4-9, this would include the maximum temperature that occurs during any of the following time periods:

- For the maximum compressive stress transient (i.e., left side of Figure 4-9), beginning at the time of algebraic minimum stress until the end of the transient.
- For the maximum tensile stress transient (i.e., right side of Figure 4-9), beginning at the start of the transient until the time of algebraic maximum stress.

Fluid temperature is an acceptable substitute for the above specified metal temperature in that fluid temperature is more readily available in CUF calculations, as it is a required input with respect to transient definitions. This is true for both older-vintage and modern-day evaluations. Since the maximum fluid temperature envelopes any metal temperature, this is conservative.

Approach #2: F_{en} Factor Calculated Based on Detailed Strain Rate

For this approach, the maximum fluid temperature of both paired transients over the time period of increasing tensile stress should be used (i.e., same as Approach #1 above).

Approach #3: F_{en} Factor Calculated Based on Integrated Strain Rate

For this approach, F_{en} is computed in an integrated fashion at multiple points between the transient pair stress valley and peak. For this case, the maximum metal temperature of both local time points considered over the period of increasing tensile stress should be used. Referring to Figure 4-5, this represents the maximum of Points i and i-1, or T = MAXIMUM(T_i, T_{i-1}). Metal temperature is more appropriate and avoids potential excess conservatism that would result from using fluid temperature in a heating event and inappropriate omission of effects in a cooling event.

For all three approaches described above, a conservative, simplified, and bounding evaluation would be to use the maximum operating temperature for the component location being evaluated. Note that it is not obvious that the use of maximum temperature in the F_{en} expressions is bounding (due to subtraction of the temperature terms), but routine application of the expressions has demonstrated that the use of the maximum temperature is bounding in all of the F_{en} expressions. This is also shown in Figure 4-6, which shows F_{en} values as a function of temperature.

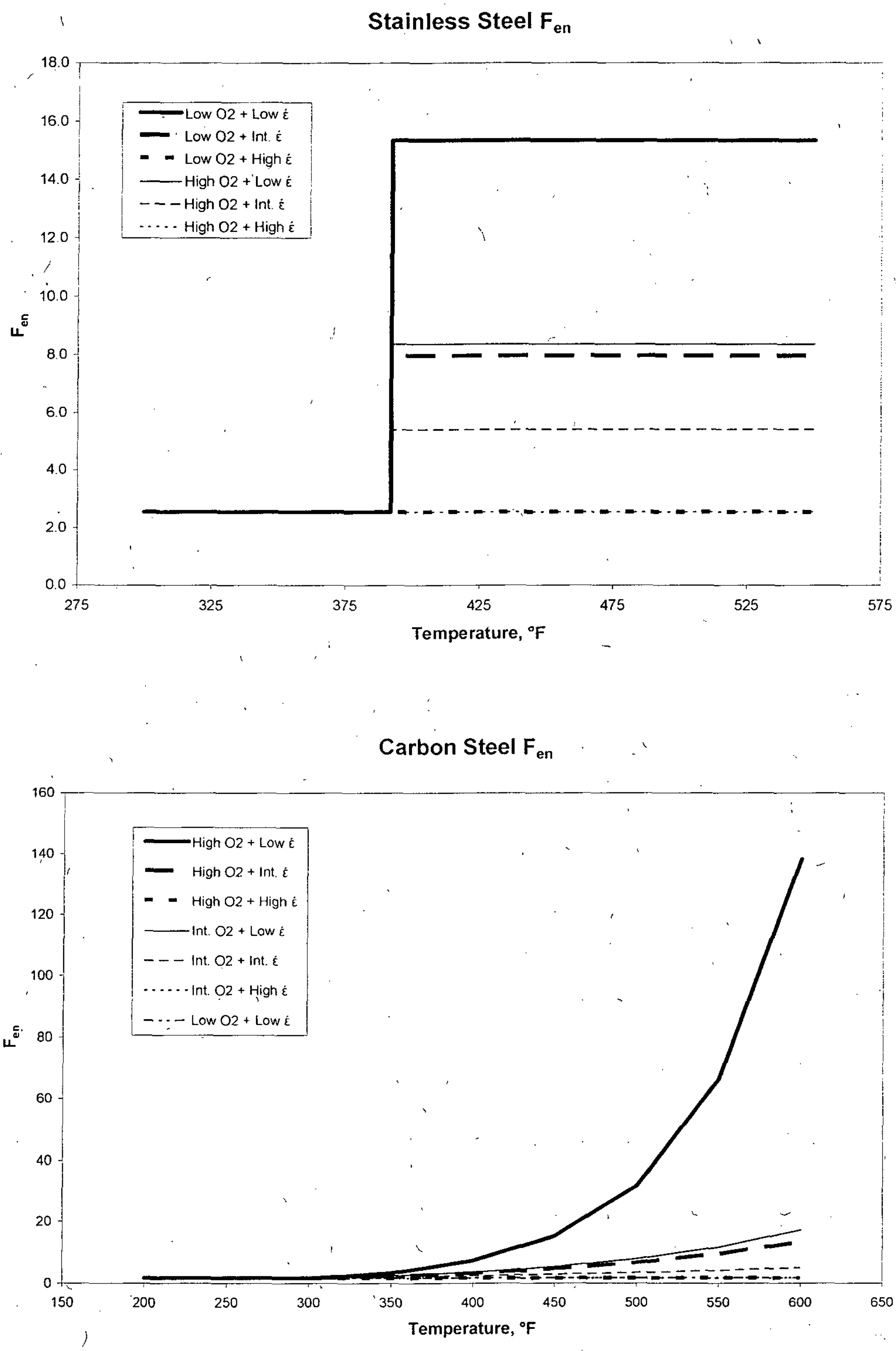


Figure 4-6
F_{en} Values as a Function of Temperature

4.2.5 Transformed Dissolved Oxygen, O*

The transformed oxygen, O*, is required by both the carbon and low alloy steel F_{en} expressions documented in NUREG/CR-6583 [3], and the stainless steel F_{en} expression documented in NUREG/CR-5704 [4], and is defined as follows:

For carbon/low alloy steels (NUREG/CR-6583 [3]):

$O^* = 0$	(DO < 0.05 ppm)
$O^* = \ell n\,(DO/0.04)$	(0.05 ppm $\leq$ DO $\leq$ 0.5 ppm)
$O^* = \ell n\,(12.5)$	(DO > 0.5 ppm)
	DO = dissolved oxygen

For stainless steels (NUREG/CR-5704 [4]):

$O^* = 0.260$	(DO < 0.05 ppm)
$O^* = 0.172$	(DO $\geq$ 0.05 ppm)
	DO = dissolved oxygen

The above expressions are straightforward to apply if the dissolved oxygen level, DO, is known. Although DO measurements are normally available through routine chemistry measurements, they are typically very limited with respect to frequency of collection and locations collected in the reactor coolant system (RCS). Therefore, there are several difficulties associated with determining the DO that is appropriate for use in the F_{en} expressions:

- The DO level is not known at the component location being evaluated. For example, it is the DO directly at the surface of the component that is required, e.g., for a BWR component exposed to saturated steam, the (much lower) DO in the condensate film is really what is applicable to an environmental fatigue analysis, not the much higher DO content of the steam itself.
- The DO level is not known at all times during a transient (i.e., perhaps DO data is only collected once per day as opposed to continuously during a transient).

As discussed in Section 4.3, there are other issues associated with DO when applying the F_{en} expressions. Solving those other issues is beyond the scope of this report, so guidance is provided in this section to address only the above two issues and answering the question, "what DO level should be used for the general transient pairing shown in Figure 4-9?" As with T*, the answer to this question is dependent upon the refinement on the evaluation used to compute the F_{en} factor. Section 4.2 contains the definitions and details for each of these three approaches. The following recommendations are made for determining the dissolved oxygen, DO, for each of the three approaches:

Approach #1: F_{en} Factor Calculated Based on Average Strain Rate Calculation

For this approach, the maximum DO level (for carbon and low alloy steels), or the minimum DO level (for stainless steels) of both paired transients over the time period of increasing tensile stress should be used. Referring to Figure 4-9, this would include the maximum (or minimum) DO level that occurs during any of the following time periods:

- For the maximum compressive stress transient (i.e., left side of Figure 4-9), beginning at the time of algebraic minimum stress until the end of the transient.
- For the maximum tensile stress transient (i.e., right side of Figure 4-9), beginning at the start of the transient until the time of algebraic maximum stress.

Approach #2: F_{en} Factor Calculated Based on Detailed Strain Rate

For this approach, the maximum DO level (for carbon and low alloy steels), or the minimum DO level (for stainless steels) of both paired transients over the time period of increasing tensile stress should be used (i.e., same as Approach #1 above).

Approach #3: F_{en} Factor Calculated Based on Integrated Strain Rate

For this approach, F_{en} is computed in an integrated fashion at multiple points between the transient pair stress valley and peak. For this case, the maximum DO level (for carbon and low alloy steels), or the minimum DO level (for stainless steels) of both local points considered over the time period of increasing tensile stress should be used. Referring to Figure 4-5, this represents the maximum of Points i and i-1 ($DO = MAXIMUM[DO_i, DO_{i-1}]$) for carbon and low alloy steels, or the minimum of Points i and i-1 ($DO = MINIMUM[DO_i, DO_{i-1}]$) for stainless steels.

For all three approaches described above, the following guidance is provided for establishing the DO level:

- In rare cases, DO level measurements are available at or near the component location being evaluated via plant instrumentation. For this case, the plant data is used directly for DO.
- In the majority of cases, DO level measurements are available at periodic intervals during plant operation. These measurements are routinely made remotely from the component location of interest. In some cases, the remote reading may be valid for application at the component location. For these cases, "typical" values can normally be determined based on consultation with the plant chemistry personnel. The typical values should be used with a brief write-up describing the basis for the values. Consideration should be given for variations in the DO level, i.e., consideration of bounding values, as described below, should be factored into the estimates.
- For cases where DO levels have changed over the course of plant operation (i.e., implementation of HWC after plant startup), a time-based average DO level is recommended, based on expected DO levels, as follows:

$$DO = \frac{DO_1 \, Time_1 + DO_2 \, Time_2 + DO_3 \, Time_3 + ...}{Time_1 + Time_2 + Time_3 + ...}$$

where:

	DO	=	time-averaged DO level
	DO_1	=	average DO level for time period $Time_1$
	$Time_1$	=	time period #1 where DO level was relatively constant
	DO_2	=	average DO level for time period $Time_2$
	$Time_2$	=	time period #2 where DO level was relatively constant
	DO_3	=	average DO level for time period $Time_3$
	$Time_3$	=	time period #3 where DO level was relatively constant
	etc.		

Thus, for a case where a BWR operated 20 years under NWC (typical DO = 200 ppb), 10 years with 50% HWC availability (typical DO = 5 ppb), and is projected to complete operation to 60 years with 95% HWC availability, the following DO level is calculated:

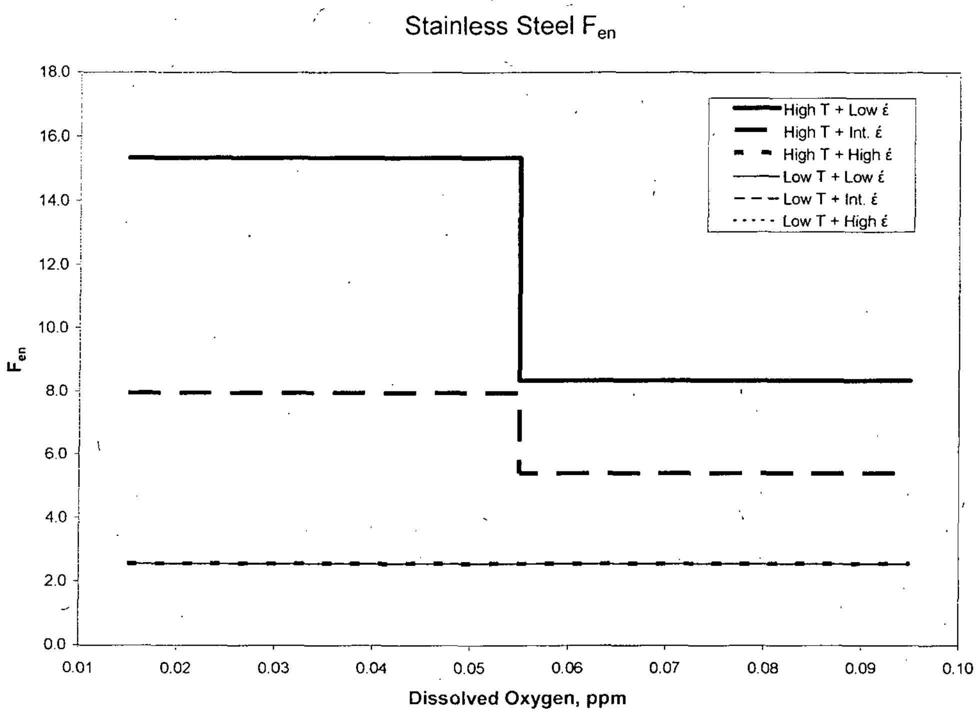
$$DO = \frac{(200x20) + (200x0.5x10) + (5x0.5x10) + (5x30)}{(20 + 10 + 30)} = 86.25 \text{ ppb}$$

Alternatively, F_{en} factors could be computed for each time period and an overall F_{en} factor calculated based on the weighted average, as follows:

$$F_{en} = \frac{F_{en,200\,ppb} \times 20 + F_{en,200\,ppb} \times 0.5 \times 10 + F_{en,5\,ppb} \times 0.5 \times 10 + F_{en,5\,ppb} \times 30}{(20 + 10 + 30)}$$

Another alternative method involves assigning a DO value to each logged transient according to the date it occurred. This is more involved than the above in that the range pair table would need to be apportioned into subsets over the past and future history of the unit and the incremental U-s re-calculated. An approximation of this would be to do a simple apportioning of the range pair U-s according to an assumed linear distribution of the occurrences, n, over the past and future historical DO values.

Similar to that described for T*, a simplified, conservative and bounding evaluation would be to use the maximum DO level (for carbon and low alloy steels), or the minimum DO level (for stainless steels) for the component location being evaluated. Note that it is not obvious that the use of these maximum or minimum DO levels in the F_{en} expressions is bounding (due to subtraction of the oxygen terms), but routine application of the expressions has demonstrated that the use of the maximum DO level is bounding in all of the F_{en} expressions for carbon and low alloy steels, and the minimum DO level is bounding in all of the F_{en} expressions for stainless steels. This is also shown in Figure 4-7 which shows F_{en} values as a function of DO level.



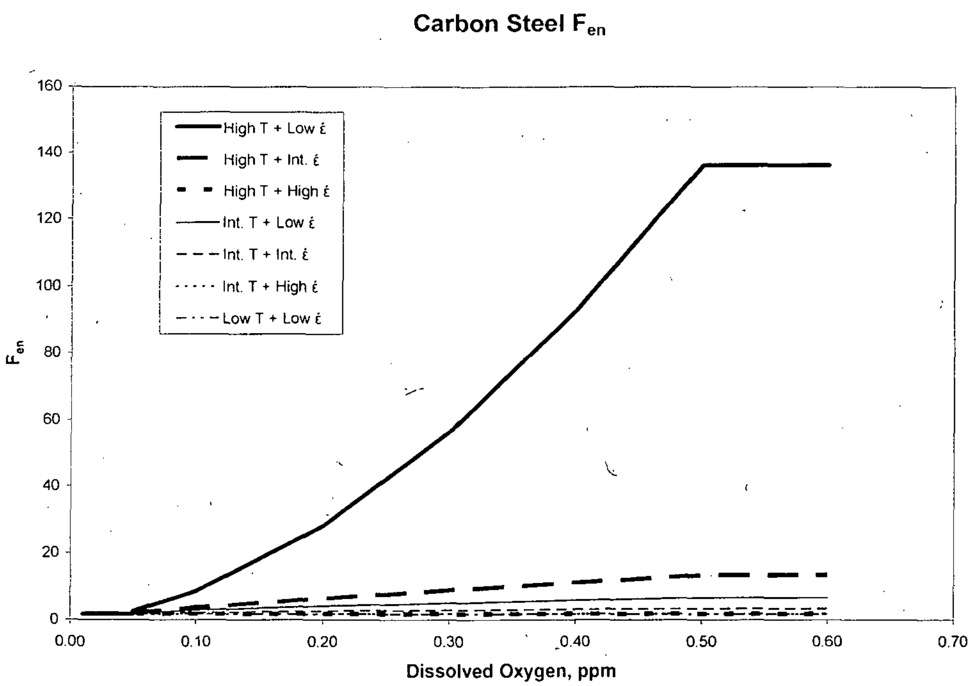


Figure 4-7
F_{en} Values as a Function of DO Level

4.2.6 Additional Considerations

The following additional considerations are provided for the above guidance:

- Dynamic Loading: For load pairs in a CUF calculation that are based on seismic or other dynamic loading, F_{en} = 1.0 for the dynamic portion of the strain for the load pair in question. This is based on the premise that the cycling due to dynamic loading occurs too quickly for environmental effects to be significant. The remaining portion of the strain range should be treated the same as discussed elsewhere in this guideline.
- Thermal Stratification Loading: For load pairs in a CUF calculation that are based solely on thermal stratification loading, the strain rate can generally be taken as the minimum strain rate that produces the maximum environmental effect. Alternatively, the strain rate effects can be determined as for any other cycle pair.
- Pressure and Moment Loading: The stresses for all load pairs in a CUF calculation typically contain stresses due to pressure and moment loading (i.e., non-thermal loads). All of the laboratory testing that forms the basis for the F_{en} expressions was conducted with alternating strain as a result of mechanical loadings, which would be analogous to pressure and moment loadings. Thus, the F_{en}s, as determined herein, should be applied to the strain ranges for cyclic pressure and moment the same as for rapid thermal effects. The effects should be considered appropriately in the Detailed and Integrated Strain Rate approaches if the available stress histories account for different rates of strain for cyclic pressure and moment strains.
- K_e: The stresses for some load pairs in a CUF calculation can contain the effect of K_e. The K_e factor causes a higher strain, thus increasing the strain rate that would be computed for affected load pair, which in turn lowers the F_{en} factor. The strain rate should instead be based on a stress history for the load pair with K_e effects removed.

4.2.7 Sample Calculation

As a demonstration of the guidance provided in Sections 4.2.2 through 4.2.5, a sample problem is provided here based on the "old" fatigue calculation shown in Figure 4-1. The completed environmental fatigue calculation is shown in Figure 4-8.

In the upper portion of Figure 4-8, the original design CUF calculation is reproduced, yielding a total CUF of 0.0067. The only additional information in this step is the total stress intensity range, SR, is computed (= Smax – Smin).

Then, environmental fatigue effects are evaluated using two approaches. Each of these approaches is described below.

Case #1: Bounding F_{en} Multiplier

For this case, since the design CUF is so low, a conservative (but very simple) approach is taken. The maximum possible F_{en} multiplier is determined and applied to the CUF result. Using the rules for low alloy steel documented in Section 4.1, the maximum F_{en} multiplier is computed as 2.45. The environmental fatigue usage factor, U_{env}, is then computed as CUF x F_{en} = 0.0164.

Case #2: Compute F_{en} Multipliers For Each Load Pair

For this case, a more refined approach is taken compared to the first approach. F_{en} multipliers are computed for each load pair. Using the rules for low alloy steel documented in Section 4.1, the overall F_{en} multiplier is also 2.45 for this approach, since the F_{en} does not vary with temperature due to the low DO. The environmental fatigue usage factor, U_{env}, for this case is also computed as 0.0164.

The following descriptions are provided for the calculations for Load Pair #1:

Salt	=	alternating stress intensity from design CUF calculation, psi
t	=	time for tensile portion of stress range in load pair, sec. Obtained from stress report from the tensile portions of both transients = 3 seconds.
Strain Rate	=	computed using the Average Strain Rate approach as 100(Salt/2)/(Et) = 100(58.77/2)/(30,000x3) = 0.03265%/sec
MAX T	=	maximum fluid temperature for tensile portion of stress range, °F. Obtained from stress report from the tensile portions of both transients = 550°F.
T*	=	T-150 since T > 150°C (550°F = 287.8°C) = 287.8 – 150 = 137.8
O*	=	0 since DO < 0.05 ppm (5 ppb = 0.005 ppm)
ε-dot*	=	ln(Strain Rate) since 0.001 ≤ Strain Rate ≤ 1%/sec = ln(0.03265) = -3.422
F_{en}	=	exp(0.898 – 0.101S*T*O*e-dot*
	=	exp(0.898 – 0.101x0.015x137.8x0x-3.422)
	=	exp(0.898)
	=	2.45

Design Basis CUF: 0.0067
Reference: Design Basis CUF Calculation Shown in Figure 4-2
Material: SA-336 (Low alloy steel)
Young's Modulus, E = 3.00E+07 psi
DO Level = 5 ppb (always)
Transformed sulfur content, S* = 0.015 (assume maximum)

Smax	Smin	SR	Salt	n	N	U
41.12	-76.41	117.53	58.77	5	1,860	0.0027
41.12	-3.55	44.67	22.34	5	40,020	0.0001
32.33	-2.69	35.02	17.51	40	95,650	0.0004
30.12	-2.69	32.81	16.41	460	133,000	0.0035
25.05	11.74	13.31	6.66	400	>1e6	0.0000
					Total CUF =	**0.0067**

Note: Above stress are in ksi. (Design CUF is reproduced!)

Approach #1: Use a Bounding F_{en} Multiplier:

Low Alloy Steel: F_{en} = exp(0.898 - 0.101S*T*O*ε*) *Reference: NUREG/CR-6583*

For a DO = 5 ppb = 0.005 ppm, O* = 0.
Therefore, F_{en} is constant vs. T = exp(0.898) = 2.45:

Maximum F_{en} = 2.45
U_{env} = CUF*F_{en} = 0.0164 (< 1.0 so acceptable!)

Approach #2: Compute F_{en} Multipliers for Each Load Pair:

Salt	t (sec)	Strain Rate (%/sec)	MAX T (°F)	T*	O*	ε-dot*	F_{en}	n	N	U*F_{en}
58.77	3	3.26E-02	550	137.8	0.00	-3.422	2.45	5	1,860	0.0066
22.34	15	2.48E-03	450	82.2	0.00	-5.999	2.45	5	40,020	0.0003
17.51	100	2.92E-04	325	12.8	0.00	-6.908	2.45	40	95,650	0.0010
16.41	1000	2.73E-05	250	0.0	0.00	-6.908	2.45	460	133,000	0.0085
6.66	300	3.70E-05	150	0.0	0.00	-6.908	2.45	400	>1e6	0.0000

Note: Above stress are in ksi.

Total = U_{env} = 0.0164
Overall F_{en} = U_{env}/CUF = 2.45
(< 1.0 so acceptable!)

Figure 4-8
Sample Environmental Fatigue Calculation

4.3 Issues Associated With F_{en} Methodology

As a result of industry application of the F_{en} relationships summarized in Section 4.1, there have been several issues identified associated with practical application of the methodology to typical industry fatigue evaluation problems. These issues have led to application of a variety of different solutions applied by analysts depending upon the analyst or the level of detail available in the existing fatigue evaluations. This varied approach has led to non-consistent application of the F_{en} approach between plants, and some amount of confusion amongst the industry.

This guideline document is formulated based on the current "state of the art" with respect to the F_{en} methodology. In many respects, the current state of the technology with respect to the F_{en} methodology is incomplete or lacking in detail and specificity. Recommendations are made in this guideline where needed to fill in these missing details. Further work should focus on the issues associated with areas where the technology is lacking. Some of the issue areas that are associated with the F_{en} methodology are summarized below ("☑" indicates where this guideline provides recommendations):

Issues of Test vs. Application

- There must be more communication between the people performing tests and those who must perform the analysis. This is one driving force behind the biannual series of "Fatigue Reactor Components" conferences that were started by EPRI in 2000. The proceedings of the most recent 2004 meeting (to be published 2005) contain several papers that address this specific issue.
- Testing for environmental effects has resulted in some rules for analysis that are not consistent with real component transient response:
  - Testing involves constant load/unload cycling, while real transients are separated in time, involve various stress magnitudes and non-constant rise times.
  - Hold time at an intermediate stress level or random load magnitude cycling has not been adequately considered in environmental testing, although some work outside the U.S. has addressed these issues.
  - The "real world" is different than laboratory tests, i.e., loading rates are random as opposed to carefully controlled ("ramped" or "saw-toothed") loads applied in the laboratory.
- Strain hardening effects may affect the results of fatigue testing at high cycles.
- May also need more nickel alloy data.

Issues of Analysis and Evaluation

- "Linking" of transients pairs is not straight-forward and can lead to significant differences in results (refer to Figure 4-9):
  - How do you treat cases where the starting and ending stress points are not equal?
  - What rate of change do you assume for the discontinuity between transients?
  - What is strain rate?
    ☑ This guideline makes recommendations in Section 4.2.2 for addressing this issue. Work is also ongoing within the EPRI BWRVIP program to investigate alternative approaches to this issue with regard to ASME Section XI calculations [25].
- Some have questioned the adequacy of Miner's Rule for fatigue analysis and that perhaps design fatigue curves should have a factor to account for this.
  - On the other hand, methods such as Rainflow Cycle Counting will generally show that the use of Miner's Rule with ASME Code analysis is conservative.
- For the purpose of component analysis for environmental effects, perhaps special stress indices and analytical methods need to be developed to distinguish between inside (fluid exposed) surfaces and external (air exposed) surfaces.
- Effect of elastic-plastic correction factor (K_e) on strain rate.
  - To neglect is conservative – how to eliminate conservatism?
    ☑ This guideline makes recommendations in Section 4.2.6 for addressing Ke.

- The F_{en} formulations for stainless steel are based on the NUREG author's own mean stainless steel S-N curve in air, which is different than the ASME mean S-N curve over the high cycle portion of the curve. Therefore, inconsistencies are present in the application of the F_{en} methods since these studies (and most applications of F_{en} being performed throughout the industry) apply F_{en} factors to fatigue results that use the ASME S-N curve.

<u>Analysis Issues: Different Loadings</u>

How are stratification loads addressed?

☑ This guideline makes recommendations in Section 4.2.6 for addressing stratification loads.

How are seismic loads addressed?

☑ This guideline makes recommendations in Section 4.2.6 for addressing seismic and other dynamic loads.

How are pressure and moment loads addressed?

☑ This guideline makes recommendations in Section 4.2.6 for addressing cyclic pressure and moment strains.

<u>Analysis Issues: Oxygen</u>

- Environmental fatigue is typically linked to dissolved oxygen. As previously mentioned, this involves inappropriate over-simplification and ignores the key role of other water chemistry parameters such as conductivity (or more correctly, level of dissolved anionic impurities) and pH. Even with regard just to dissolved oxygen, however:
  - Experts say oxygen is not the correct parameter – should be electrochemical potential (ECP), which is affected by the overall balance of oxidants and reductants in the water, as well as by temperature, flow, surface condition, etc. ECP, rather than dissolved oxygen, is the control parameter used in BWR water chemistry guidelines in the context of stress corrosion cracking mitigation.
  - Hydrogen water chemistry (HWC) may produce much different results, as the oxygen level is significantly lowered for HWC operation (for some locations).
  - What oxygen level to use?
    - Time history during transients not generally available.
    - Value at component location not generally available.
    - What about different periods of operation, i.e., NWC for first 15 years, then intermittent HWC, then reliable HWC?
    - If time history is available:
      - Maximum or minimum of transient?
      - Maximum or minimum local?, i.e., MAX(DO_i, DO_{i-1})
      - Maximum or minimum between peak and valley?

☑ This guideline makes recommendations in Section 4.2.5 for addressing varying historical oxygen levels.

Analysis Issues: Temperature

- Temperature:
  - What temperature to use?
    - Metal? (not generally available)
    - Fluid?
    - Maximum of transient?
    - Maximum local?, i.e., MAX(T_i, T_{i-1})
    - Maximum between peak and valley?

    ☑ This guideline makes recommendations in Section 4.2.4 for addressing temperature.

Analysis Issues: Defining Design Loads

- The strain range (and therefore the CUF) decreases as an imposed temperature change is applied over a longer time period. The longer time period results in a slower strain rate and, all other things being equal, the slower strain rate produces a larger F_{en}. Therefore, a challenge presents itself with respect to defining a set of transients (and their associated temperature ramp rates) that are bounding for design purposes. Component-specific preliminary studies have shown that the F_{en}-adjusted CUF for a variation of temperature ramp rates reaches a maximum when the temperature variation is on the order of 1,000°F/hour or higher [26]. Further investigations are expected to show that it will be possible to define design transients in a manner that will determine the maximum F_{en}-adjusted CUF as the temperature ramp rate (and thus the strain rate) is varied in a narrow range from approximately 1,000°F/hour (or other component-specific rates) to infinite rates. These efforts mirror similar work on crack growth in reactor components through corrosion fatigue [25], and it is expected that such efforts will demonstrate that the issue of defining a transient with a range of ramp rates, extracting the strain rates, performing the design, and monitoring for compliance are all very manageable when utilizing the F_{en} approach for design.

As noted, several of the issues identified above were addressed earlier in this report. Those recommendations are intended to serve as a guide for performing environmental fatigue evaluations. The remaining issues that are not addressed in this report are beyond the scope of the work associated with this report at the current point in time, and some are impossible to resolve with information currently available. An example would be the issue of using ECP/conductivity as a more appropriate parameter for assessing environmental effects. All current F_{en} methodologies are based on measured dissolved oxygen, as that was the only water chemistry parameter recorded during laboratory testing. The remaining non-addressed issues represent the limitations on the current state of the art. As further industry work is completed to address some of the remaining issues summarized above, refinements or additions to these guidelines may be made to further define and enhance plant specific evaluations. Therefore, these guidelines can be thought of as an "instruction manual" for performing plant specific environmental fatigue evaluations based on the current state of technology and information available. Resolution of the remaining non-addressed issues is not needed in order for license renewal applicants to satisfy the current regulatory requirements of addressing reactor water environmental effects.

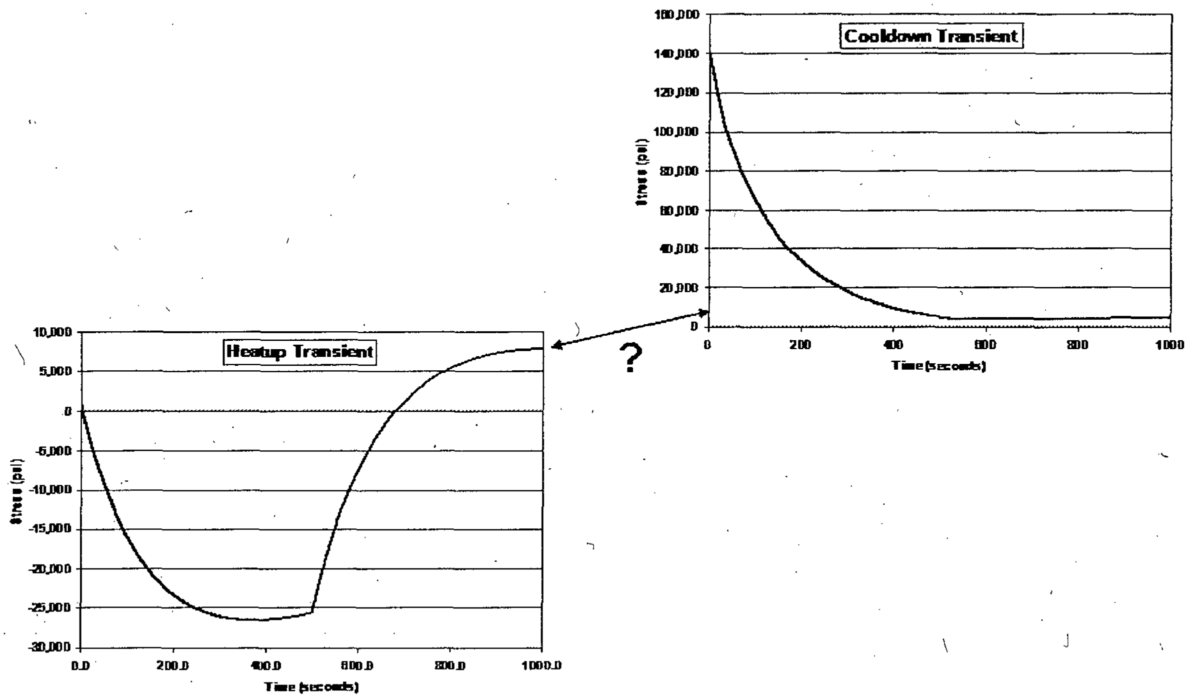


Figure 4-9
Issue of Transient Linking

5 CONCLUSIONS

This report has provided guidance that may be used by individual license renewal applicants to address the environmental effects on fatigue in a license renewal application. The approaches documented in this report are geared to allow individual utilities to determine the optimum approach for their plants, allowing different approaches to be taken for different locations.

The overall approach taken for license renewal is to select a sampling of locations that might be affected by reactor water environmental effects. NUREG/CR-6260 locations are considered an appropriate sample for F_{en} evaluation as long as none exceed the acceptance criteria with environmental effects considered. If this occurs, the sampling is to be extended to other locations. An assessment of the chosen locations is undertaken: (1) to show that there is sufficient conservatism in the design basis transients to cover environmental effects, or (2) or to derive an expected fatigue usage factor including environmental effects. Then, either through tracking of reactor transient cycles or accumulated fatigue usage, utilities can determine if further steps must be taken to adequately manage fatigue environmental effects in the extended operating period.

Different methods are outlined for managing fatigue in the extended license renewal period should fatigue limits be exceeded. These include component re-analysis, fatigue monitoring, partial cycle counting, etc. Flaw tolerance evaluation as outlined in ASME Code, Section XI, Nonmandatory Appendix L, coupled with component inspection verifying the absence of flaws, is also included, although further work is underway by the Code to satisfy past regulatory concerns. Component repair/replacement is also a possibility, but this option is typically reserved to instances where other more economical approaches cannot show acceptable results.

Consistent with current ASME Code, Section XI philosophy for conducting additional examinations when flaws are found in service, the recommendations in this guideline include expansion of the number of locations tracked if fatigue limits are exceeded in the extended operating period. In addition, utilities will continue to monitor operating plant fatigue experience, especially with respect to cracking that might indicate a strong contribution from fatigue environmental effects.

Guidance for performing plant specific environmental fatigue evaluations for selected locations is provided. The intent is to unify the process used by applicants to address environmental effects in the License Renewal Application, and provide specific guidance on the use of currently accepted environmental fatigue evaluation methodologies. The guidance provided by this report is considered to be "Good Practice".

Using the guidance provided in this report, the amount of effort needed to justify individual license renewal submittals and respond to NRC questions should be minimized, and a more unified, consistent approach throughout the industry should be achieved.

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A
SURVEY OF APPROACHES USED TO-DATE FOR ADDRESSING FATIGUE ENVIRONMENTAL EFFECTS IN THE EXTENDED OPERATING PERIOD

This appendix summarizes the approaches for addressing fatigue environmental effects in the extended operating period used by those applicants that have already submitted the license renewal application.

Plant	License Renewal Approach	Extended Operating Period Commitment
Calvert Cliffs	Environmental fatigue calculations will be performed for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules Develop Class 1 fatigue analysis for the B31.1 piping locations	Continue to monitor fatigue usage Component with a CUF > 1.0 will be added to the fatigue monitoring system
Oconee	Concluded that the effects of fatigue are adequately managed for the extended period with EAF to be addressed prior to Year 40 Based on 4 EPRI studies and Oconee confirmatory research NUREG/CR-6260 RPV locations accepted via NRC staff SER for BAW-2251A	Update allowable cycles for remaining three locations (all SS) based on EAF adjusted CUF using NUREG/CR-5704 but with a Z-factor of 1.5 Continue to monitor fatigue usage via cycle/severity counting/comparison Participate with EPRI in additional confirmatory research on this issue
ANO-1	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules The EAF for the RPV components specified in NUREG/CR-6260 were determined to be acceptable for the period of extended operation For the piping components, the surge line and HPI nozzles and safe ends had CUF > 1.0. These components are included in the RI-ISI program.	Continue to monitor fatigue usage, and do one of the following for the components where CUF > 1.0: refinement of the fatigue analysis in an attempt to lower the CUF to < 1.0 repair of affected locations replacement of affected components management of the effects of fatigue during the period of extended operation using a program that will be reviewed and approved by the staff through the RI-ISI program

Plant	License Renewal Approach	Extended Operating Period Commitment
Hatch	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules Assumed HWC conditions Used 60-year projections of actual cycles and actual fatigue usage to-date (higher than 40-year design basis in some cases) Environmental CUF < 1.0 for 60 years at all locations except reactor recirculation nozzles and feedwater piping	Continue to monitor fatigue usage, perform a refined analysis for feedwater piping and recirculation nozzles before Year 40
Turkey Point	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules Revised NUREG/CR-6260 calculations to incorporate power uprate and NUREG/CR-6583 and -5704 methods Used 60-year projections of actual cycles (same as design basis) Environmental CUF < 1.0 for 60 years at all locations except surge line hot leg nozzle	Continue to monitor fatigue usage, aging management for surge line
North Anna/Surry	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules Scaled plant-specific results based on results in NUREG/CR-6260 Used 60-year projections of actual cycles (same as design basis) Environmental CUF < 1.0 for 60 years at all locations except surge line elbow	Continue to monitor fatigue usage, aging management for surge line
Peach Bottom	Did not perform environmental fatigue calculations for NUREG/CR-6260 locations Committed to do so before Year 40	Continue to monitor fatigue usage, perform environmental fatigue calculation before Year 40

Plant	License Renewal Approach	Extended Operating Period Commitment
St. Lucie	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules Refined several Class 1 fatigue analyses to offset F_{en} impact Used 60-year projections of actual cycles (same as design basis) Environmental CUF < 1.0 for 60 years at all locations except surge line elbow	Continue to monitor fatigue usage, aging management for surge line
Ft. Calhoun	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules Revised NUREG/CR-6260 calculations to incorporate NUREG/CR-6583 and -5704 methods Used 60-year projections of actual cycles (same as design basis) Refined surge line Class 1 fatigue analysis to offset F_{en} impact *–Note from OPPD: The refined surge line analysis has already been completed because of pressurizer replacement and power uprate activities, so the surge line had to be reanalyzed for other reasons and wasn't done for License Renewal alone. Otherwise, it probably would still be a pending action.* Environmental CUF < 1.0 for 60 years at all locations	Continue to monitor fatigue usage

Plant	License Renewal Approach	Extended Operating Period Commitment
McGuire/ Catawba	Committed to perform environmental fatigue analysis based on NUREG/CR-6583 for carbon and low-alloy steels and on NUREG/CR-5704 for austenitic stainless steels	Perform environmental fatigue analysis before the end of the 40th year of plant operation Choose sample locations from those in NUREG/CR-6260 and other locations expected to have high EAF adjusted CUF, to ensure that no plant location will have an EAF-adjusted CUF that exceeds 1.0 in actual operation Determine the EAF adjusted CUF using defined transients and/or assumed occurrences which bound or coincide with realistic expectations for an evaluation period Continue to monitor fatigue usage via cycle/severity counting/comparison using EAF adjusted allowable cycles or via tracking EAF adjusted CUF
Robinson	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules Revised number of load/unload events to show acceptability Used 60-year projections of actual cycles (same as design basis) Environmental CUF < 1.0 for 60 years at all locations except surge line	Continue to monitor fatigue usage, aging management for surge line
Ginna	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules The EAF for all components specified in NUEG/CR-6260 were determined to be acceptable for the period of *extended operation, with the* exception of the pressurizer surge line Plant specific F_{en} factors for the piping locations, based on the ASME Class 1 fatigue analysis done in NUREG/CR-6260, were applied to Ginna-specific design basis fatigue usage to determine the environmental fatigue values	Continue to monitor fatigue usage Prior to the end of the current license period, the *pressurizer surge nozzle will be inspected*

Plant	License Renewal Approach	Extended Operating Period Commitment
Summer	The thermal fatigue management program will be revised by the end of the current licensing term to base future projections on 60 years of operation and to account for EAF	assess EAF before the end of the current licensing period
Dresden/ Quad Cities	Did not perform environmental fatigue calculations for NUREG/CR-6260 locations Committed to do so before Year 40	Continue to monitor fatigue usage, perform environmental fatigue calculation before Year 40
Farley	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 Fen rules Used existing Class 1 fatigue analysis for all NUREG/CR-6260 locations, except surge line and BIT tee to RHR/SI piping Developed Class 1 fatigue analysis for surge line using stress-based fatigue software Used actual fatigue usage to date (based on available stress-based data) and design number of cycles for the surge line Developed Class 1 fatigue analysis for BIT tee to RHR/SI piping using Summer 1979 ASME piping rules The EAF for all components specified in NUREG/CR-6260 were determined to be acceptable for the period of extended operation with the exception of the charging nozzle and RHR locations	Continue to monitor fatigue usage Prior to the end of the current license period, the charging and RHR locations will be addressed further
ANO-2	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 Fen rules Environmental CUF < 1.0 for 60 years for all RPV locations For the pressurizer surge line, charging nozzle and shutdown cooling line CUF > 1.0, safety injection nozzle < 1.0	Continue to monitor fatigue usage, and do one of the following for the components where CUF > 1.0: refinement of the fatigue analysis in an attempt to lower the CUF to < 1.0 repair of affected locations replacement of affected components management of the effects of fatigue during the period of extended operation using a program that will be reviewed and approved by the staff through the RI-ISI program

Plant	License Renewal Approach	Extended Operating Period Commitment
Cook	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules Developed Class 1 fatigue analysis for three B31.1 piping locations Used 60-year projections of actual cycles and actual fatigue usage to-date (higher than 40-year design basis in some cases) Environmental CUF < 1.0 for 60 years at 5 of 6 locations. The environmental CUF was greater than 1.0 for the pressurizer surge line.	Continue to monitor fatigue usage
Browns Ferry	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules Refined several Class 1 fatigue analyses to offset F_{en} impact Separate oxygen values computed for HWC and NWC conditions, applied based upon historical and projected system availability. Used 60-year projections of actual cycles and actual fatigue usage to-date (higher than 40-year design basis in some cases) Environmental CUF < 1.0 for 60 years for all RPV locations, piping locations > 1.0 TVA is developing Class 1 fatigue analysis for piping locations	Continue to monitor fatigue usage, perform analysis for piping locations

Plant	License Renewal Approach	Extended Operating Period Commitment
Point Beach	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules The EAF for all components specified in NUEG/CR-6260 were determined to be acceptable for the period of extended operation Fatigue monitoring software used to calculate spray line usage Used plant operating data to analyze fatigue for piping locations since design CUF values were not available	Continue to monitor fatigue usage
Brunswick	Performed environmental fatigue calculations for NUREG/CR-6260 locations using NUREG/CR-6583 and NUREG/CR-5704 F_{en} rules Refined several Class 1 fatigue analyses to offset F_{en} impact Developed Class 1 fatigue analysis for two B31.1 piping locations Separate oxygen values computed for HWC and NWC conditions, applied based upon historical and projected system availability. Used 60-year projections of actual cycles and actual fatigue usage to-date (higher than 40-year design basis in some cases) Environmental CUF < 1.0 for 60 years at all locations	Continue to monitor fatigue usage

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R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Director

BWR WATER CHEMISTRY

Many of the stress corrosion problems in boiling water reactors (BWRs) result from the presence of a very small amount of dissolved oxygen in the reactor water. Radiolysis in the reactor core continually decomposes a small amount of the very pure water used in BWRs into free oxygen and hydrogen. Most of the gas is stripped from the water by the steam, leaving only trace amounts of oxygen and hydrogen dissolved in the reactor water. Although the amount of dissolved oxygen is only about 200 ppb, it is sufficient to facilitate stress corrosion cracking. Hydrogen water chemistry can reduce dissolved oxygen to a level that will no longer facilitate stress corrosion.

Pipe cracking in BWRs first came to the attention of U.S. electric utilities in 1974. This problem has resulted in costly repairs and lost operating time. The potential seriousness of the problem was recently emphasized by the discovery of cracks in large-diameter (26-in; 660-mm) recirculation piping at a domestic BWR. These cracks necessitated replacement of the complete recirculation piping system and will cost 12 to 18 months of operating time.

Earlier EPRI reports (*EPRI Journal*, September 1981, p. 6; November 1981, p. 18) have helped familiarize the industry with the various factors involved in pipe cracking. In most cases, cracks have resulted from intergranular stress corrosion cracking (IGSCC). This status report describes how changing reactor water chemistry can help prevent IGSCC.

Three conditions must be present simultaneously for IGSCC to occur: stress, a sensitized microstructure, and an environment (water chemistry and temperature) that will facilitate cracking. Theoretically, no pipe will ever crack if any one factor is completely eliminated. Eight pipe-cracking remedies have been developed: three that affect stress, three that affect sensitization, and two that affect environment (Table 1). By their very nature, all the stress and sensitization remedies are limited to the specific component to which they are applied. For example, induction heating stress improvement affects cracking in the pipe weld to which it is applied; it does not affect any other weld. Only the water chemistry remedies have the potential of protecting the whole system.

The water in a BWR is similar in purity to laboratory distilled water. It is converted into steam by reactor core heat, condensed into liquid again after passing through the turbine, and reconverted into steam on reentering the core. This process is repeated continuously.

During reactor operation, radiolysis in the reactor core continually decomposes a small amount of water to form free oxygen and hydrogen. Most of the oxygen and hydrogen is stripped from the water by the steam and is subsequently removed from the water circuit by special equipment in the condenser. However, about 200 ppb oxygen and 12 ppb hydrogen remain dissolved in the water in the core when the reactor is at the steady-state full-power operating temperature (288°C; 550°F). During reactor startups and shutdowns oxygen concentration varies with temperature (Figure 1). The important question of which temperature-oxygen combinations facilitate IGSCC has been answered in part under EPRI research (RP1332 and RPT115). The shaded IGSCC danger zone in the figure represents those combinations.

Table 1
CAUSES AND REMEDIES FOR BWR PIPE CRACKING

Cause	Remedy
Stress	Induction heating stress improvement
	Heat sink welding
	Last-pass heat sink welding
Sensitization	Solution heat treatment
	Corrosion-resistant cladding
	Alternative materials
Environment	Hydrogen water chemistry
	Impurity control

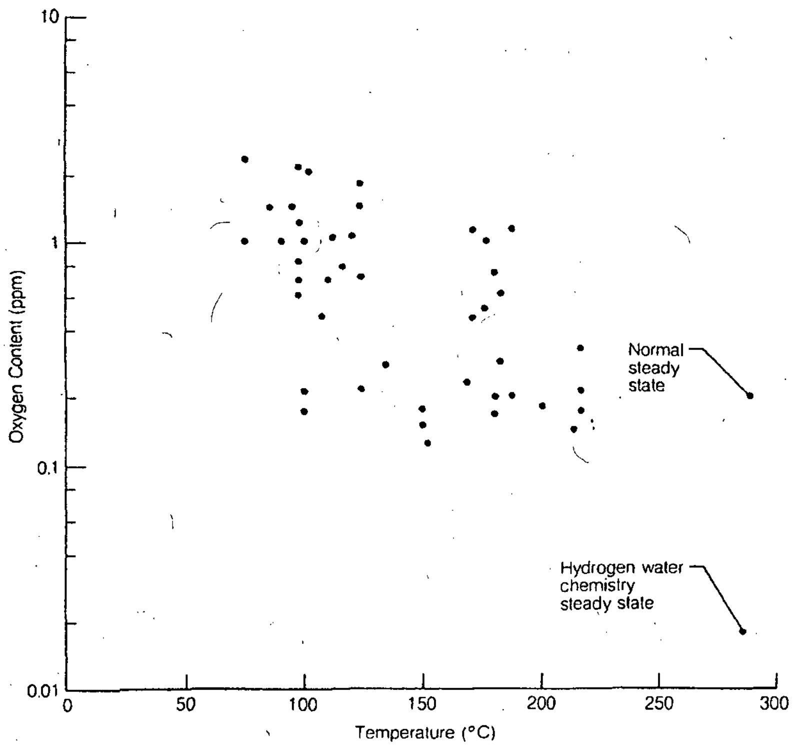
Reducing oxygen levels during reactor startups and shutdowns by deaeration has been highly publicized in the BWR industry. Although helpful during transients, this remedy does little, if anything, to reduce pipe cracking during steady-state conditions (RP1332-2, RPT112-1, RPT115-3, RPT115-4). Deaeration does not affect oxygen levels during steady-state operating conditions, which definitely facilitate IGSCC. The amount of time spent at steady state is about 140 times greater than the amount of time spent in startups. Therefore, to reduce IGSCC further, it is necessary to change water chemistry during steady-state conditions.

Hydrogen water chemistry

In hydrogen water chemistry, small amounts of hydrogen gas are added to the reactor feedwater. In the reactor core the added hydrogen recombines with oxygen and other radiolysis products to suppress the net amount of oxygen produced at the steady-state temperature (Figure 1).

Although hydrogen water chemistry experiments were conducted over 20 years ago in several early Norwegian and U.S. test reactors, the concept was not further developed until 1979, when the Swedish utilities and ASEA–Atom conducted a short eight-hour test of hydrogen water chemistry at Oskarshamn-2 and demonstrated that hydrogen water chemistry was economically feasible. In 1981 the Swedes conducted a second test at Oskarshamn-2 for four days and obtained detailed water chemistry measurements. These tests showed that hydrogen water chemistry lowered the oxygen concentration to levels that would no longer be expected to facilitate stress corrosion. However, no actual in-reactor corrosion tests were performed. In June 1982 DOE funded

Figure 1 The shaded area represents the temperature-oxygen combinations that facilitate IGSCC in high-purity water. The data points are examples of temperature-oxygen combinations that have been measured in operating BWRs during startup, shutdown, normal steady state, and hydrogen water chemistry steady state.



a 30-day hydrogen water chemistry experiment at Commonwealth Edison Co.'s Dresden-2 plant. During this experiment, EPRI sponsored in-reactor stress corrosion tests that helped confirm hydrogen water chemistry as a powerful antidote for stress corrosion problems (RP1930-2). A $1 million EPRI laboratory research project on hydrogen water chemistry, which has been in progress for two years, supports this conclusion (RP1930-1).

The combined results of the in-reactor and laboratory IGSCC tests show that the oxygen level must be suppressed to 20 ppb to eliminate IGSCC completely. For example, during the Dresden-2 test, a severely sensitized sample of stainless steel was tested under extreme stress and strain, and absolutely no IGSCC was detected. In laboratory tests on full-scale pipes the growth rates of preexisting cracks have been slowed by a factor of 10 as a result of hydrogen water chemistry. If no cracks are present before hydrogen treatment of water, no new cracks are expected to start.

To achieve an oxygen level of 20 ppb during the Dresden-2 test, it was necessary to add 1.5 ppm hydrogen to the feedwater and to use pure oxygen in the off-gas system instead of air. The total cost of both hydrogen and oxygen was less than $1000/day. If a BWR had a 70% capacity factor and a remaining lifetime of 20 years, the total would be about $5 million. Equipment installation would cost an additional $1 million. In contrast, replacement of a complete recirculation piping system is estimated to cost on the order of $500 million, including the cost of replacement power.

Although the stress corrosion benefits from hydrogen water chemistry are expected to be very high, at least one negative side effect exists. The amount of the radioactive isotope nitrogen-16 (N-16) in the steam will increase. The N-16 is formed in the reactor core by the nuclear reaction: oxygen-16 + neutron $\longrightarrow$ nitrogen-16 + proton. Under normal water chemistry conditions the N-16 reacts with dissolved oxygen to form nitrate (NO_3^-), which is soluble in the reactor water.

Under hydrogen water chemistry conditions there is not enough dissolved oxygen to react with the N-16 to form NO_3^-; the N-16 combines with the hydrogen to form ammonia, NH_3. Ammonia is a volatile gas and is therefore removed from the water by the steam. The N-16 is a very unstable isotope and decays with a half-life of 7.11 s, giving off high-energy gamma rays. Because more N-16 ends up in the steam when hydrogen water chemistry is used, the steam lines and steam turbine will emit more gamma radiation than when normal BWR water chemistry is used. At Dresden-2, the amount of N-16 gamma radiation increased by a factor of 5 during the hydrogen water chemistry test. The turbine is heavily shielded and therefore the increase in N-16 did not significantly increase the radiation dose rate to plant personnel. In general, the N-16 side effect was manageable during the tests at Dresden-2. When maintenance crews had to enter an area where N-16 radiation was high, the hydrogen injection was stopped, and N-16 radiation levels quickly returned to normal. After the maintenance crew left the area, the hydrogen injection was resumed.

The major uncertainties about hydrogen water chemistry revolve around the possibility of long-term negative side effects. The two most important concerns are the hydrogen embrittlement of the nuclear fuel cladding and the redistribution of corrosion products (radiation buildup) within the plant. Although the best technical judgment available indicates that the possibility of either of these effects becoming unmanageable is extremely remote, there is no data base on which to build firm conclusions. At least one fuel cycle with hydrogen water chemistry will be required before a recommendation can be made to the utilities. EPRI is developing a long-term in-reactor test program to address these major uncertainties.

Control of Impurities

Although reactor water contains impurities in small amounts (at the ppm or ppb levels), BWRs generally operate with high-purity water. For example, NRC guidelines specify that reactor water chloride (Cl) concentration be kept below 0.2 ppm and the conductivity below 1 $\mu S/cm$ during plant operation. A solution containing 1 ppm of sodium chloride (NaCl) would have a conductivity of about 2 $\mu S/cm$ and a Cl concentration of 0.6 ppm. Therefore, 1 ppm of NaCl would exceed the NRC specifications. The results of EPRI research projects have shown that maintaining water purity may be just as important as controlling oxygen levels (RP1563-2, RPT115-3, RPT115-6). Impurities increase the size of the IGSCC danger zone.

In accelerated laboratory IGSCC tests as little as 1 ppm of certain impurities eradicated hydrogen water chemistry benefits. To benefit from hydrogen water chemistry, utilities will have to control both oxygen levels and conductivity. Reactor water with only 20 ppb oxygen and a conductivity in the vicinity of 0.2 μS/cm may eliminate any possibility of IGSCC. EPRI has recently stepped up its research to understand the role of impurities in an effort to produce cost-effective water chemistry guidelines. *Project Manager: Michael Fox*

VALVE RESEARCH

The primary goal of valve research in EPRI's Nuclear Power Division is to reduce the amount of plant unavailability attributable to valves in LWR power plants. These R&D activities seek to improve valve maintenance practices and valve performance and reliability and thus reduce the cost of producing electricity. EPRI's initial effort in this area was an assessment of industry valve problems conducted in the mid 1970s (NP-241). It was found that nuclear plant unavailability attributed to valves, valve actuators, and associated control circuits represented approximately three forced outages per plant per year, with an average outage duration of about two days. The value of such unavailability is significant. A study reported in the June 1982 EPRI Journal *(p. 18) indicates that a 1% availability improvement in base-load coal and nuclear generating units combined would represent savings of $2.2 billion nationwide over the seven-year study period.*

In the initial assessment of industry valve problems, which was conducted by MPR Associates, Inc., the concept of key valves evolved. These are valves whose malfunction can result in a forced plant outage, a power reduction, or an extension of a planned outage. It is basically to these valves that the EPRI research effort is directed.

The study concluded that only a small percentage (5–10%) of the total valve population in a nuclear power plant is applied in such a way that failure would result in a forced outage. It should be noted that these key valves are not necessarily safety-related valves. No major differences were found between PWRs and BWRs regarding the causes (seat leakage, stem leakage, actuator malfunction) of valve-related shutdowns.

The study also concluded that forced outages attributable to valves are underreported because of an umbrella or shadowing effect—situations where a valve requires maintenance or repair work during an outage attributed to another system or component. Thus, although the valve could be considered a contributing cause of the outage, this is not reflected in the reported data.

Nuclear plant data collection and evaluation systems originally had many shortcomings. As a result of improvements in these systems, data quantity and usefulness have been increased. Other existing sources of information remain to be assimilated, however, to achieve a comprehensive view of the problem. EPRI's limiting-factors analysis studies, the findings of which are published in four reports (NP-1136 through NP-1139), provide further insight into the causes and the magnitude of nuclear plant availability losses attributable to valves.

On the basis of the efforts described above, two areas were selected for initial EPRI R&D attention: the seat leakage performance of main steam isolation valves (MSIVs) in BWRs and valve stem packing improvements for both PWR and BWR application.

Figure 2 presents a cutaway view of a representative MSIV with the valve bonnet and the actuator removed. Two identical MSIVs are installed in series in each BWR steam line. Technical specifications for BWR plants establish maximum allowable seat leakage rates for MSIVs and require the periodic testing of each valve to verify that this requirement is met.

Work was initiated in early 1979 with Atwood and Morrill Co., Inc., a manufacturer of MSIVs, and General Electric Co., the nuclear steam supply system contractor for BWR plants, to develop a comprehensive test program on MSIV seat leakage performance (RP1243-1, RP1389-1). The goals were first to identify the factors that affect the valves' capability to meet the seat leakage criteria imposed by the local leak rate test (LLRT) and then to identify and verify the effectiveness of corrective actions for improving valve leakage performance.

The program evaluated the effects of such factors as local residual stresses from valve installation welding; forces and moments applied by the connecting pipe; mechanical cycling; thermal cycling; excessive wear and corrosion of critical valve surfaces; and poorly controlled maintenance practices. Of the factors investigated, corrosion of the valve seating surface (or changes in the friction coefficient) and inadequate maintenance practices were found to be the most significant contributors to the seat leakage problem. Program results are reported in NP-2381 and NP-2454.

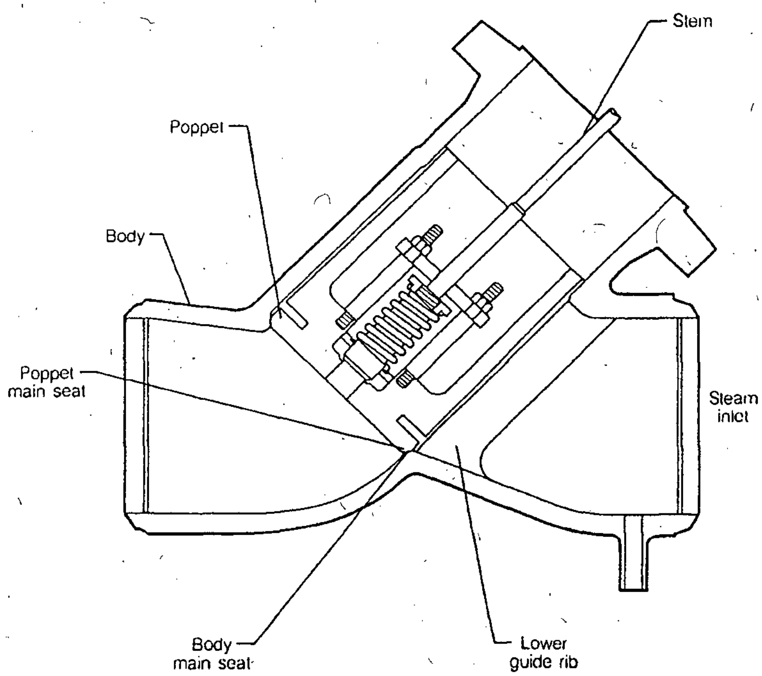


Figure 2 BWR main steam isolation valve. EPRI has sponsored a test program to determine the factors that affect valve seat leakage performance and to evaluate ways to improve this performance.

NEC-JH_66

FACTOR of 12

Fatigue Crack Propagation Rates for Notched 304 Stainless Steel Specimens In Elevated Temperature Water

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Fatigue crack propagation (FCP) rates for 304 stainless steel (304 SS) were determined in 24°C and 288°C air and 288°C water with 20–60 cc H_2/kg H_2O using double-edged notch (DEN) specimens. Tests performed at matched loading conditions in air and water provided a direct comparison of the relative crack growth rates over a wide range of test conditions. Crack growth rates of 304 SS in water were about 12 times the air rate for both short cracks (0.03–0.25 mm) and long cracks up to 4.06 mm beyond the notch, which are consistent with conventional deep crack tests. The large environmental degradation for 304 SS crack growth is consistent with the strong reduction of fatigue life in high hydrogen water. Further, very similar environmental effects were reported in fatigue crack growth tests in hydrogen water chemistry (HWC). Prior to the recent tests reported by Wire and Mills [1] and Evans and Wire [2], most literature data in high hydrogen water showed only a mild environmental effect for 304 SS, of order 2.5 times air or less. However, the tests were predominantly performed at high cyclic stress intensities or high frequencies where environmental effects are small. The environmental effect in low oxygen environments at low stress intensity depends strongly on both the stress ratio, R, and the load rise time, T_r. Fractographic examinations were performed on specimens tested in both air and water to understand the operative cracking mechanisms associated with environmental effects. In 288°C water, the fracture surfaces were crisply faceted with a crystallographic appearance, and showed striations under high magnification. The cleavage-like facets suggest that hydrogen embrittlement is the primary cause of accelerated cracking. [DOI: 10.1115/1.1767859]

1 Introduction

Fatigue crack propagation data for Type 304 stainless steel (304 SS) were obtained in air and an elevated temperature aqueous environment. The data were developed from instrumented fatigue tests on double-edged notched (DEN) fatigue specimens with two different notch root radii ρ of 0.38 and 1.52 mm, reported by Wire et al. [3]. The fatigue tests were primarily designed to determine the effect of notch radius on fatigue crack initiation but also provide fatigue crack growth data for both shallow and long cracks. Direct comparison of crack growth rates obtained in air and water under identical loading conditions and for equivalent crack sizes demonstrates that 304 SS experiences a large environmental effect, and the detailed analysis below shows that this trend was supported by all tests.

2 Experimental

The DEN specimens (Fig. 1) were machined from a 127 mm diameter bar forging with an L-C orientation per ASTM E1823, with yield and ultimate strength of 288 and 546 MPa. The chemical composition of the 304 SS material is provided in [1]. The microstructure consists of nonsensitized grains with a grain size of ASTM 2.

Load-controlled cyclic fatigue tests were performed in air at room temperature and 288°C and in deaerated 288°C water. The electric potential drop (EPD) technique with current reversal was used to monitor crack initiation and growth, as detailed in [1].

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The double-edge notched uniaxial specimen provides two sites for crack initiation. It provides an advantage over compact tension specimens in that it can be tested in both tension-tension and tension-compression loading conditions. Tests were performed under load control in fully reversed ($R=-1$) and tension-tension loading ($R=0$). Alignment was achieved by manually adjusting the pull rod to minimize bending stresses, which were monitored by strain gages attached to the specimen (Fig. 1). Once a satisfactory alignment was achieved, the strain gages were removed and the EPD leads were attached. For the tests in water, the assembly was then enclosed in an autoclave, which was filled with water and heated to 288°C. Deaerated water containing 20 to 60 cc H_2/kg H_2O was used in this study. The room temperature pH was 10.1 to 10.3, and the oxygen concentration was less than 20 ppb. The specimen was cycled until crack initiation was detected, based on the electrical potential drop reading corresponding to a crack growth of 0.13 mm. Following an interim visual inspection, cycling was continued to obtain crack extension data.

The crack growth rate da/dN was calculated using the secant method applied to the average extension curves, as discussed by Wire [1]. Crack growth rates were obtained at extensions as low as 0.013 mm in order to investigate possible short crack effects. For conventional deep cracks, rates were calculated over larger increments of crack extension.

For shallow cracks, of depth $L<\rho$ from the notch, the stress intensity factor solution developed by Schijve [4] for a crack emanating from an edge notch was used to compute K. When the crack depth exceeded the notch root radius, the conventional stress intensity factor solution developed by Tada et al. [5] for DEN specimens, which is based on the total crack depth including the notch depth, was used to calculate K. The transition between the two formulations was made at $L=\rho$. It is noted that an inde-

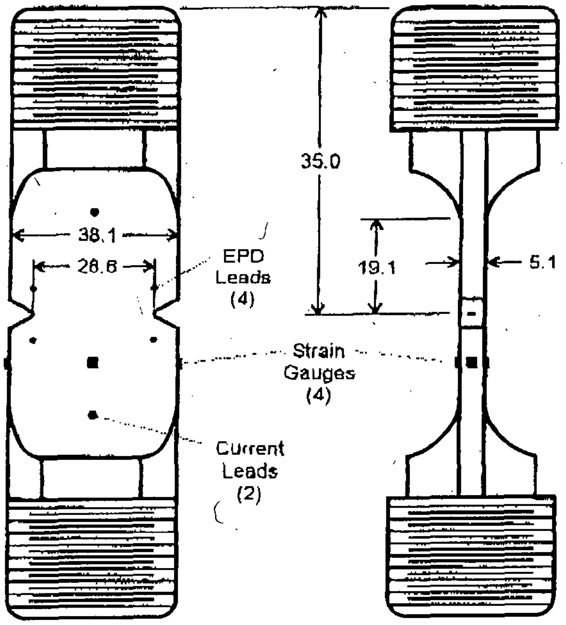


Fig. 1 Double-edge notched fatigue specimen with EPD (Grip details not shown, all dimensions in mm)

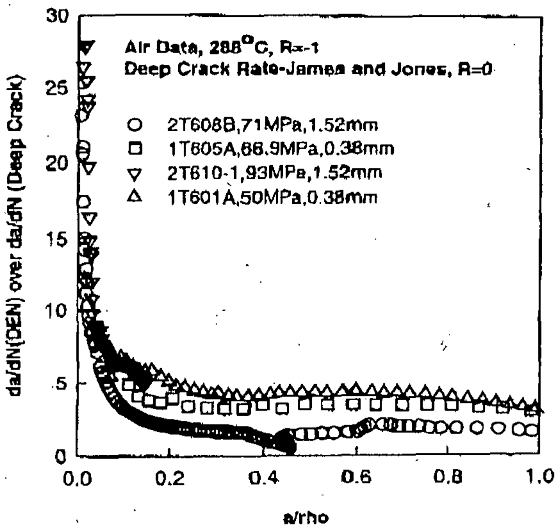


Fig. 2 Short crack growth rates from DEN specimens. Rates normalized by deep crack rates using positive ΔK, Eq. 2

pendent K solution for a double-edge notched plate by Yamamoto [6] provided results within 4% for shallow and intermediate crack lengths over the range of the present tests. For both the fully reversed and tension-tension tests, the stress intensity factor range (ΔK) is defined as the difference between K at maximum and minimum loads (i.e., $\Delta K = K_{max} - K_{min}$). Crack asymmetry is a potential problem with the DEN specimen. However, the largest difference observed between the two cracks was 2 mm out of an overall crack length ($D+L$) of about 9 mm. The 2 mm difference is less than 5% of the specimen width of 38 mm, indicating crack asymmetry is not a problem for this data.

Broken specimen halves were examined on a scanning electron microscope (SEM) to characterize the fatigue fracture surface morphology. The crack length associated with each fractograph was determined so fracture surface features could be correlated with crack growth rates and applied ΔK levels. Relative amounts of α' martensite on fracture faces were estimated using a commercial ferrite measurement instrument (Feritscope® MP3C). While fracture surface roughness and the presence of only a thin layer of martensite precluded precise measurements, relative amounts of martensite were readily determined.

3 Test Results

3.1 Short Crack Effects. Before examining environmental effects, it is appropriate to evaluate the cracking behavior for short versus long cracks. Crack growth rates for short cracks can be much larger than long crack data due to differences in crack closure according to Newman [7]. Crack closure in the crack wake reduces the portion of the load that is effective in growing a crack. However, short cracks have little or no crack wake, and closure is subsequently reduced. To examine for such closure effects, the growth rates in air for the DEN at $R=-1$ were compared directly to growth rates from conventional deep crack tests in air at 288°C, $R=0$ per James and Jones [8]:

$$da/dN = 1.40\times 10^{-9}\Delta K^{3.57},\ \text{mm/cycle},\ \Delta K \text{ in MPa}\sqrt{\text{m}} \quad (2)$$

The ratio of the DEN rates to rates for long cracks from Eq. (2) are shown in Fig. 2. It was convenient to use only the positive portion of the loading to calculate the air rates for long cracks, as the ratio in Fig. 2 then decreased to values near unity at large crack depths. The figure shows that the short crack growth rates can exceed the deep crack rates by a factor of thirty, but that the ratio quickly approaches a stable value as the crack depth becomes significant compared to the notch radius. The value of the ratio at larger crack depths ranged from approximately one to four for the tests shown, implying that the tensile portion of the loading is largely responsible for the crack propagation at large crack depths. For the particular notch depths studied here, short crack effects are only important below L/ρ of order 0.2. Therefore, shallow crack effects can produce an order of magnitude increase in crack growth rates under fully reversed loading conditions, but this acceleration is confined to very small crack extensions, on the order of 0.1 to 0.3 mm. For longer cracks, conventional test data for deeply cracked specimens can be used to predict cracking behavior.

The increased rates observed for short cracks near notches is consistent with increased effective stress intensity, as reviewed in depth by Lalor, Sehitoglu, and McClung [9]. They observed that the crack opening stress increased rapidly with increasing crack depth and leveled out for crack depths above approximately 40% of the notch radius. They were able to explain the observed crack opening stresses on the basis of finite element analysis of crack closure effects.

3.2 Environmental Effects by Comparison to Controls. The effect of environment on fatigue crack growth can be seen by directly comparing the data from 288°C air and water tests, as controls were run in air at the same or very similar loading conditions to the tests in water. This allows a direct assessment of environmental effects down to the smallest detectable crack extensions, while avoiding the need for an explicit treatment of short crack effects. Hence, the da/dN values in air and water are compared directly at the same crack extension and cyclic stress. This assures that crack driving forces are the same, without having to explicitly calculate them.

Figure 3 shows conclusively that the crack growth rates in water are much enhanced over rates in air. The ratio of crack growth rates in water over air is called the environmental ratio (ER), for convenience. At a stress amplitude of 69 MPa and lowest frequency tested of 0.0033 Hz, the ER is 15 (Fig. 3(a)). The large ER in water observed in Fig. 3(a) persisted to the end of the test, where the crack extension was 4.1 mm. Hence, large environmental effects continue to crack depths of engineering significance,

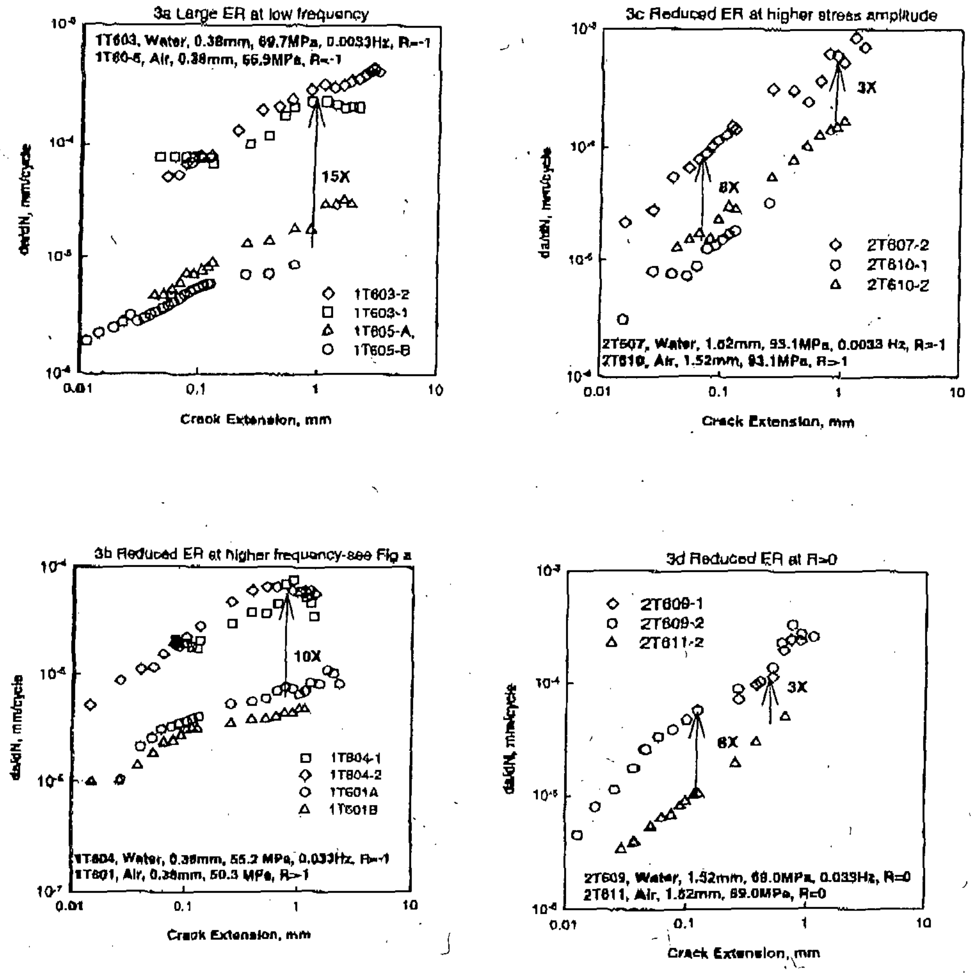


Fig. 3 Environmental effects in DEN tests. Stress amplitude and other test parameters on plots

and are not just a short crack phenomenon. Figure 3 shows that the ER was large at the smallest detectable crack extensions of about 0.025 mm. Hence, the increases in crack growth rate explain the reductions in fatigue life reported in the literature [10].

Several other trends are worthy of note. Higher frequency led to a smaller ER of 10×, as shown by comparing Fig. 3(b) and Fig. 3(a). The apparent increase in ER with decreasing frequency is consistent with the reduction of fatigue life at low strain rate noted by Chopra and Smith [10]. The ER for a higher stress amplitude (Fig. 3(c)) is only about a factor of 8× compared to 15× in Fig. 3(a) at the same low frequency, indicating a reduction in ER at high stress amplitude and crack growth rates. The ER at $R=0$ is also smaller, as shown in Fig. 3(d). This may be further evidence of an effect of higher effective loading for a given stress amplitude provided by $R=0$ compared to $R=-1$, which has a compressive half cycle. Also, the ER in Fig. 3(c,d) decreases at the largest crack extensions, which correspond to the highest stress intensity. Such an effect is consistent with the general notion that at high loading, mechanical effects will dominate.

3.3 Environmental Effects Using Time-Based Plots and Comparison to Literature. From a fundamental point of view, the crack tip strain rate is the appropriate crack driving parameter to correlate environmentally assisted crack propagation rate data, as reviewed by Scott [11]. However, a unique method of crack-tip strain-rate calculation could not be established and variability in calculated values was over a factor of ten between various models. Shoji et al. [12] suggested using the time-based rate in air as a practical correlating parameter representing crack tip strain-rate for low alloy steel fatigue crack growth data. This variable was used successfully to correlate environmental effects on low alloy steels in water. The time-based crack growth in air $(da/dt)_a$ is defined as

$$(da/dt)_a=(da/dN)_{air}/T_r \quad \text{where } T_r \text{ is the load rise time} \tag{3a}$$

and the time based environmental rate $(da/dt)_e$ in water is

$$(da/dt)_e=(da/dN)_e/T_r \tag{3b}$$

Eq. (3) is appropriate for fatigue crack growth tests with continuous cycling, which produce a time-independent rate such as seen in the present tests. In the event that stress corrosion cracking or other time-dependent behavior is operative, the total time would be more appropriate in Eq. 3.

The strong environmental effects observed on 304 SS are correlated reasonably well by utilizing a time-based plot, as shown in Fig. 4, although data variability is large. The air rates for DEN specimens were determined directly from the control tests in air, as shown in Fig. 3. The 304 SS DEN data (diamonds) show a clear increase in crack growth rates relative to those in air at low air rates, and are consistent with the degradation of fatigue life of up to 15× reported by Chopra and Smith [10] and 13× reported by Leax [13]. As noted above, the large ER did not diminish in one test up to a crack depth of 4.1 mm. This depth is greater than associated with "short crack" effects and is significant from an engineering standpoint. Subsequent tests on conventional compact tension specimens at this laboratory, represented by the circles in

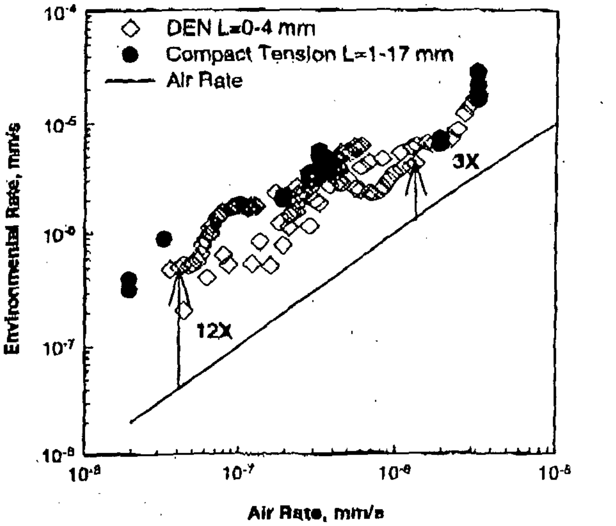


Fig. 4 304 SS DEN crack growth rates in water vs air. Trend shows decreased ER at high air rate. Air rates are calculated directly from control tests

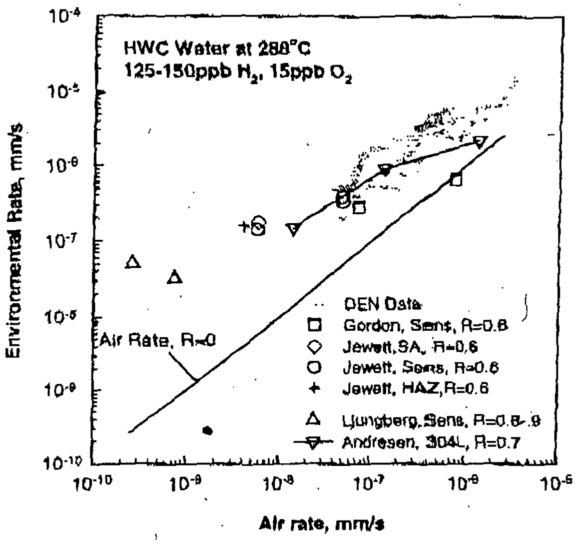


Fig. 6 Comparison of DEN to CT data in HWC Large environmental effects extend to low air rates

Fig. 4, verify that the environmental effect continues unabated to a crack growth of 17 mm, as reported by Evans and Wire [2]. For 304 SS CT data, the baseline crack growth rate in air, $(da/dN)_{air}$, was determined via [8] for the appropriate test conditions (i.e., ΔK, R, and temperature). It is also noted that the agreement between short crack and long crack results indicates that there is no "chemical" enhancement of crack growth of short cracks, such as reported by Gangloff [14] for high strength steel in a NaCl solution.

A review of fatigue crack propagation of austenitic stainless steels was performed recently by Shack and Kassner [15]. Data from surface crack tests performed in low oxygen "hydrogen water chemistry" (HWC) environments by Prater et al. [16] are compared with DEN data in Fig. 5. HWC is BWR water chemistry with hydrogen added to control the electrochemical potential. The literature tests on surface crack specimens tested in HWC water confirm that the large environmental effects shown here have been observed previously. Overall, the surface crack tests from the literature average about 14 times the air rate, very similar to DEN data. Indeed, crack growth rates in HWC at frequencies between 1.67×10^{-2} and 5.56×10^{-4} Hz are identical to those obtained in this study. The fact that the stainless steel studied by Prater was sensitized does not appear to be important, as the cracking mode was transgranular. Gordon et al. [17] indicated that the fatigue crack growth rates in HWC water were the same for solution annealed and sensitized 304 SS, and Jewett et al. [18] reported very similar rates in these materials as well as welds.

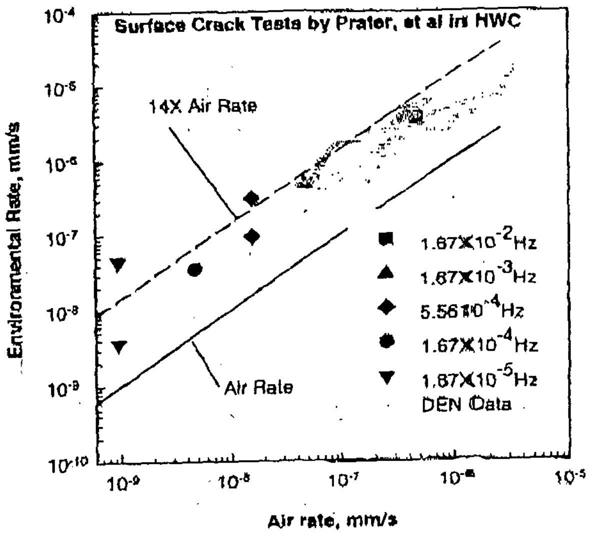


Fig. 5 Comparison of DEN to surface crack data. Surface crack data tested in HWC [16]

A comparison of crack growth data trends from DEN tests and selected conventional compact tension test data in HWC is provided in Fig. 6. The DEN and CT data are in good agreement in the intermediate growth rate regimes where both specimen types were evaluated. Moreover, the data by Ljunberg [19] show even greater enhancement in the low crack growth rate regime. These results provide further support for the observation that environmental effects tend to increase in the lower stress intensity regime where crack growth rates in air are reduced.

The tests by Andresen and Campbell [20] show evidence for a transition to reduced environmental effects at high equivalent air rates, and more limited data by Gordon et al. [17] are consistent with such an effect. It is noteworthy that the DEN data agree qualitatively with HWC data in Fig. 6, including evidence of a transition to substantially lower environmental effects at equivalent air rates above 10^{-6} mm/s.

The hydrogen level for the HWC test data in Figs. 5 and 6 is 150 ppb or less, much less than several ppm in the current DEN tests and in PWR water. Although the corrosion potential in HWC is typically about 0.3 V SHE higher than that in water with higher hydrogen used in the present tests, according to Gilman [21], the overall crack growth rate response in the two environments appears to be similar.

3.4 Effects of Stress Ratio, Stress Intensity, and Rise Time. Evans and Wire [2] performed a series of tests on a 1.9T CT specimen (thickness=24.1 mm) of the same heat and water conditions used in the DEN tests. The CT tests showed that large environmental effects occurred in conventional, deeply cracked compact tension specimens with high hydrogen levels and the attendant lower potential. Results from the DEN tests and the compact tension tests by Evans and Wire (2002) are shown in Fig. 7. For DEN data represented in Figs. 7–8, the full cyclic stress range and crack extensions increments of 0.12 mm or larger were employed.

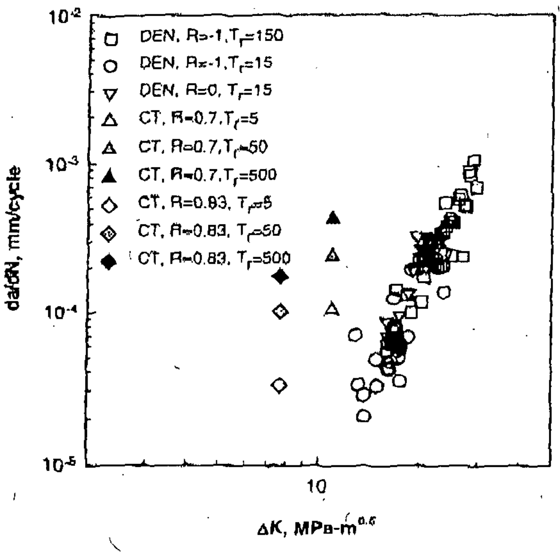


Fig. 7 304 SS crack growth rates in water at 288 °C. Rise time (T_r) is in seconds

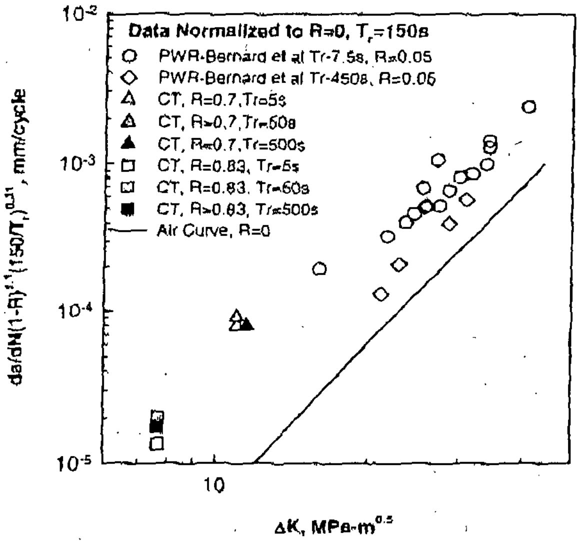


Fig. 9 Normalized 304 SS CT FCP Data at Low Potential. Normalization: $(1-R)^{-1.1}$, $T_r^{0.31}$ to $R=0, T_r=150$ s

The results in Fig. 7 indicate a strong effect of both T_r and R. The environmental effects can be rationalized in terms of a combined mean stress effect on closure or R ratio and a rise time or frequency effect, consistent with the literature. Bamford [22] noted larger environmental effects at higher R ratios. He incorporated an effective $\Delta K_{off}=K_{max}(1-R)^{0.5}$, which shifted the high R data more in line with low R data. Cullen [23] reported strongly increased FCP rates for cast stainless steel at higher R in PWR water. The data by Bernard et al. [24] on Z3 CND17-12, similar to 316 SS, showed a clear rise time effect in PWR water. Recently, a correlation for FCP of austenitic stainless steels in BWR water was developed by Itatani et al. [25]. The correlation was of the form

$$da/dN=A(\Delta K)^m T_r^n/(1-R)^p \quad \text{with } m=3.0, \quad n=0.5, \text{ aidand } p=2.12 \tag{4}$$

This formulation indicates a strong role of T_r and R, consistent with results described above in low oxygen water. It is noted that the present crack growth rates are similar to those reported by Itatani et al. [25] in BWR water in the few cases where data are available at similar T_r, R, and ΔK. Figure 8 shows that the crack growth rates in Fig. 7 can be reasonably well normalized by $T_r^{0.31}$ and $1/(1-R)^{1.1}$. Hence, the form of the correlation developed by Itatani et al. for tension-tension appears to be promising for tension-compression. Further, the present rise time and stress ratio R ratio dependence are consistent with all but the very high R (0.95) BWR water data utilized by Itatani et al. [25]. Figure 9 shows that normalization in Fig. 8 worked successfully on data from compact tension tests at high R by Evans and Wire [2] and at low R by Bernard et al. [24]. Both data sets include long rise times (450–500 s) where environmental effects are substantial. The plot shows that ER reduces to about 2× at large ΔK. While the selected parameters values correlate these limited data sets, much more data would be required to obtain a definitive correlation.

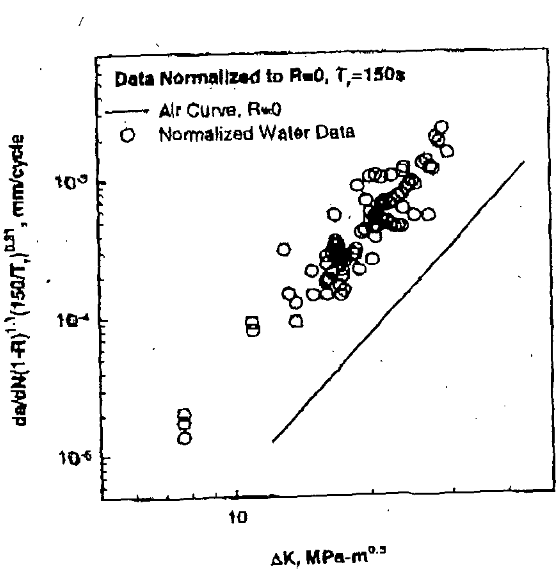


Fig. 8 Normalized 304 SS FCP Data [illegible]

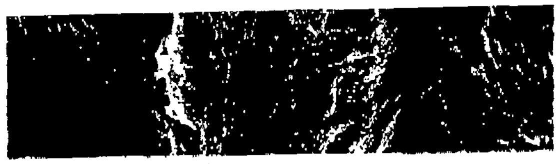
4 Characterization of Fatigue Crack Propagation Mechanisms

Fracture surface features for specimens tested in air and water were evaluated to correlate operative cracking mechanisms with environmental cracking behavior. The fracture surface appearance for specimens tested in room temperature air was found to be dependent on loading conditions. A faceted morphology (Fig. 10(a)) was observed at crack growth rates less than 1×10^{-4} mm/cycle, vast fields of well-defined striations were generated between 1×10^{-4} and 1×10^{-3} mm/cycle, and a combination of fatigue striations and dimples (Fig. 10(b)) was observed above 1×10^{-3} mm/cycle. The nature of striated fracture surfaces in the intermediate and high crack growth rate regimes resembles that typically observed in FCC materials, but the facets formed at low crack growth rates are rather unique, as discussed below. Evidence of rubbing and fretting (Fig. 11) due to repeated contact between mating fracture surfaces was observed in specimens tested under fully reversed cyclic loading conditions.

Facets generated at low crack growth rates had an irregular appearance that was associated with a quasi-cleavage mechanism

...... for Data vs ΔK. Normalization: $(1-R)^{-1.1}\ T_r^{0.31}$ to R=0, T_r=150 s

that was operative for both shallow and deep cracks, as long as crack growth rates were less than 1×10^{-4} mm/cycle. Because



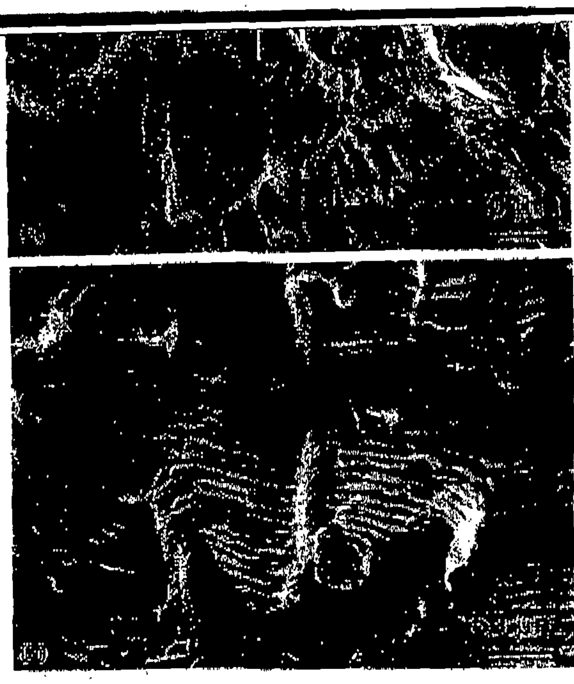


Fig. 10 Fractographs of 304 SS tested in 24°C air. (a) Irregular quasi-cleavage facets at $da/dN=8\times10^{-6}$ mm/cycle. Arrow denotes failed twin boundary. (b) Striations and dimples at 1×10^{-2} mm/cycle

Fig. 11 Repeated contact between crack surfaces ($R=-1$). (a) Rub marks at low ΔK levels in 288°C air. (b) Striations surrounded by severely rubbed regions (24°C air).

304 SS is a metastable alloy at room temperature, the material directly ahead of an advancing crack undergoes a strain-induced transformation to α' martensite. Therefore, cracks propagate through martensite, which results in a quasi-cleavage morphology that resembles the quasi-cleavage fracture surface appearance in martensitic steels. Ferritescope measurements showed that all fatigue fracture surfaces generated at room temperature contained α' martensite, with the amount of martensite increasing at higher stress intensity factor levels due to larger plastic zone sizes.

The morphology of the quasi-cleavage facets was consistent with the fracture surface appearance for 304 SS (Gao et al. [26]) and high purity Fe-18Cr-12Ni SS (Wei et al. [27]) tested in room temperature air, 3.5% NaCl solutions and hydrogen. Strain-induced α' martensite formed ahead of fatigue cracks in both alloys, which caused a quasi-cleavage mechanism. Unlike 304 SS, 316 SS fatigue tested in room temperature air (Mills [28]) exhibited more conventional, cleavage-like facets. Because 316 SS is a more stable alloy due to its higher nickel content, α' martensite transformation does not occur at room temperature; hence, it exhibits classic, cleavage-like faceted growth as cracks propagate through stable austenite.

In the low crack growth rate regime, 304 SS also exhibited localized cracking along annealing twin boundaries, but no evidence of intergranular cracking. Localized separation along favorably oriented twin boundaries produced flat, featureless facets that appear as dark islands, surrounded by quasi-cleavage facets. Gao et al. [26] and Wei et al. [27] also reported twin boundary cracking in 304 SS and high purity Fe-18Cr-12Ni SS.

Facets formed in 288°C air had a different morphology, as they took on a more conventional cleavage-like appearance. Comparison of Figs. 12(a) and 12(b) shows that the high temperature facets had more of a crystallographic nature with some evidence of river patterns, in contrast with the irregular facets generated in room temperature air. The lack of quasi-cleavage facets indicates that 288°C is above the critical temperature where cold working induces a martensite transformation (i.e., M_D temperature). Based on the composition of 304 SS, the M_D temperature associated with 30% cold work is on the order of 100°C (Lacombe [29]). Indeed, Ferritescope measurements showed no detectable α'-martensite on fatigue fracture surfaces generated at 288°C.

At crack growth rates slightly above 1×10^{-4} mm/cycle, facets formed in 288°C air were poorly defined and parallel fracture markings associated with slip offsets were often superimposed on them. The transition to poorly defined facets is believed to be associated with a transition from heterogeneous-to-homogeneous slip. Fracture surfaces generated in 288°C water were remarkably different than those generated in air. Facets formed in water had a crystallographic appearance with well-defined river patterns, as shown in Fig. 12(c). The sharp, cleavage-like facets formed immediately adjacent to machined notches and well away from the notches, indicating that the same faceted growth mechanism was operative for shallow and long cracks. Moreover, well-defined crystallographic facets persisted over the entire range of crack growth rates generated in this program, including crack growth rates as high as 8×10^{-4} mm/cycle where fracture surfaces generated in air exhibited poorly defined facets and vast fields of fatigue striations. There was no evidence of either intergranular cracking or annealing twin boundary cracking in 288°C water.

Although fracture surfaces generated in 288°C water exhibited crisp cleavage-like facets, high magnification of facet faces revealed the presence of fatigue striations (Fig. 13). At crack growth rates from 1×10^{-4} to 3×10^{-4} mm/cycle, parallel fracture mark-

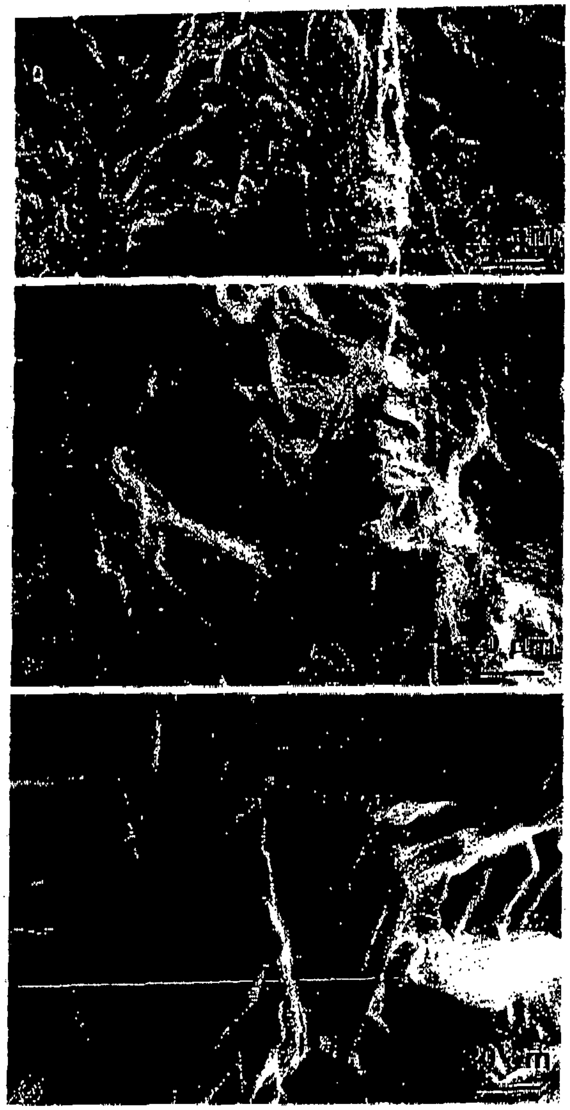


Fig. 12 Fractographs of 304 SS fatigue tested in (a) 24°C air showing irregular facets (b) 288°C air showing cleavage-like facets (c) 288°C water with crystallographic facets that are sharp, cleavage-like, and highly angular.

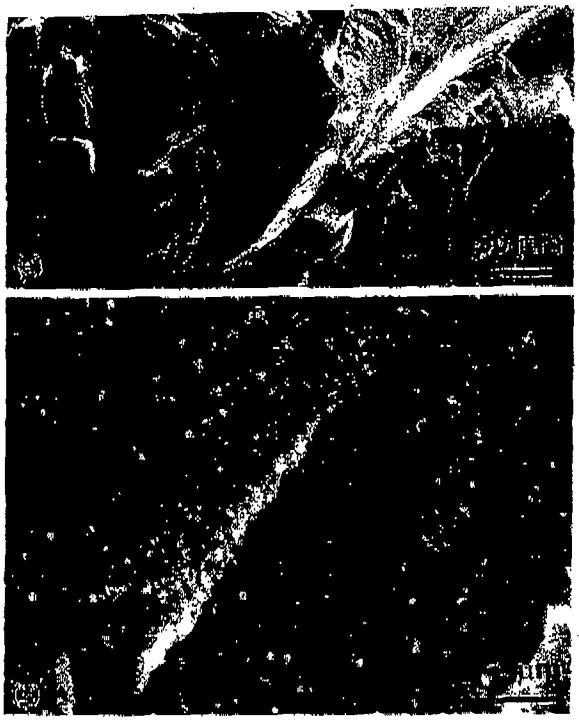


Fig. 13 Fractographs of 304 SS fatigue tested in 288°C water. (a) Highly angular faets persist to 3×10^{-4} mm cycle. (b) High magnification of (a) shows fatigue striations superimposed on facet faces

ings on the facets were very straight, but their spacing was identical to macroscopic crack growth rates indicating that they were fatigue striations. At growth rates above 3×10^{-4} mm/cycle, striations had a ductile or wavy appearance, as shown in Fig. 13(b).

Facet and striation orientations on fracture surfaces generated in 288°C water revealed that local cracking directions were often very different from the overall cracking direction. Although facets were usually aligned in the cracking direction, some were aligned normal to the macroscopic cracking direction (Figs. 12(c) and 13(a)). Likewise, most striations were oriented normal to overall cracking direction, but in some regions striations had different orientations and in some cases were even parallel to the macroscopic cracking direction. These observations indicate that crack advance in water involved a very uneven process, as cracking first occurred in the most susceptible regions, which left ligaments in the wake of the advancing crack front. As the overall crack continued to extend, local stress intensities within the more resistant ligaments increased to the point where cracking reinitiated and propagated across the ligaments. As a result, local cracking directions within these ligaments were often normal to the overall cracking direction. The rapid crack advance in the more susceptible regions is believed to be a significant contributor to the environmental acceleration observed in high temperature water. Specifically, this rapid cracking not only increased the overall crack length, it increased local stress and provided alternate paths for reinitiating local cracks along the more resistant ligaments.

The role of active path dissolution versus hydrogen embrittlement in causing accelerated cracking of stainless steel in high temperature water remains an issue because of the coupled nature of these processes, as electrochemical reactions near the crack tip involve both anodic dissolution of the metal and a cathodic reaction that produces hydrogen. The presence of well-defined crystallographic features indicates the absence of significant metal dissolution, thereby suggesting that slip/dissolution is not the primary cause of accelerated cracking. This observation is consistent with findings by Chopra and Smith [10] that crack growth rates for 304 SS are greater in low dissolved oxygen water than in high dissolved oxygen water. This observation cannot be reconciled with a slip/dissolution mechanism.

The presence of sharp, crystallographic facets suggests that a hydrogen embrittlement mechanism is responsible for accelerated cracking in 288°C water. This is supported by fractographic findings by Hanninen and Hakarainen [30] where hydrogen-precharged 304 SS exhibited cleavage-like facets without any detectable α' martensite formation. The facet morphology for the hydrogen-precharged specimens is very similar to that observed in 288°C water, thereby implicating hydrogen in promoting accelerated cracking in high temperature water. Moreover, Gao et al. [26] and Wei et al. [27] demonstrated that a hydrogen embrittlement mechanism was responsible for accelerated fatigue crack growth rates in stainless steel alloys tested in room temperature aqueous environments. Although α' martensite formation occurred in these specimens, Gao and Wei determined that this transformation did not have a critical role in controlling crack growth rates and it was not a prerequisite for hydrogen embrittlement.

Although hydrogen embrittlement is believed to be the primary cause of environmental cracking in 288°C water, it is possible that oxide film formation at the crack tip also affects cracking behavior by restricting slip reversals during the unloading portion of fatigue cycles. The importance of oxide film formation in affecting fracture surface morphology is apparent when comparing fracture surfaces generated in air and vacuum. Fatigue fracture surfaces generated in air possessed crystallographic facets, whereas those generated in vacuum had a nondescript, nonfaceted appearance (Wire [1]). Apparently, the thin oxide film that forms in 24°C air serves as a dislocation barrier that impedes slip reversals during unloading cycles. Hence, damage tends to be concentrated along particular slip bands, and eventually local separation along these slip bands produces crystallographic facets. In vacuum, the absence of an oxide film promotes more effective slip reversals that minimizes local damage along any particular slip band. As a result, crystallographic facets do not develop in vacuum. Oxide film formation in water is also expected to restrict slip reversals and promote facet formation and higher crack growth rates; however, the degree of acceleration is expected to by much less than that associated with hydrogen embrittlement.

In summary, it is unlikely that slip/dissolution is a primary cause of environmental cracking in 288°C hydrogenated water because of the presence of crisp crystallographic features and an increase in crack growth rates with decreasing dissolved oxygen levels (Chopra and Smith, [10]). The cleavage-like facets on the fracture surface, which are very similar to facets found in hydrogen-precharged 304 SS (Hanninen and Hakarainen [30]), suggest that hydrogen embrittlement is the primary cause of accelerated cracking in high temperature water. It is also likely that the formation of crack tip oxides restricted slip reversals which also contributed to increased crack growth rates, although this effect is expected to be much smaller effect than that associated with hydrogen embrittlement.

5 Summary and Conclusions

Instrumented corrosion fatigue tests on 304 SS DEN specimens provided fatigue crack growth rate data in 24° and 288°C air and 288°C water over a wide range of crack growth rates. Results in air and water at the same mechanical parameters allowed direct assessment of environmental effects, avoiding any concerns for data variability due to materials, test technique, and data correlation. Crack growth rates in water are about 12× times the air rate at low speeds where the environmental effects are largest. The large environmental degradation in crack growth is consistent with the strong reduction of fatigue life in commercial PWR water. Further, very similar crack growth rate data were reported in low oxygen HWC, in both surface crack and conventional deep crack tests. The large environmental enhancement in 304 SS (12×) persisted to crack extensions up to 4.1 mm, far outside the range associated with short crack effects. The same large environmental effects observed in the DEN tests were reproduced in CT specimens at a high stress ratio and low ΔK. The overall results can be normalized successfully by incorporating the combined effects of stress ratio and rise time, qualitatively similar to the formulation developed by Itatani et al. to describe test results in BWR water.

Much of literature data in hydrogenated water chemistry shows an apparently mild environmental effect for 304 SS, with an ER of 2.55 or less. However, based on the current test results, larger environmental effects occur in hydrogenated water in the low ΔK regime at long rise times and high R-ratio conditions.

The high crack growth rates in 288°C deaerated water were associated with a faceted growth mechanism. The highly angular, cleavage-like appearance of the facets suggests that a hydrogen embrittlement mechanism was the primary cause of accelerated cracking in this environment.

Acknowledgment

This work was performed under U.S. Department of Energy Contract with Bechtel Bettis, Inc. The authors wish to acknowledge the efforts of H. K. Shen, A. J. Bradfield, J. T. Kandra, and J. J. Chasko in performance of these experiments.

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UNITED STATES
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY LICENSING BOARD

In re:	Docket Nos. 50-247-LR and 50-286-LR
License Renewal Application Submitted by	ASLBP No. 07-858-03-LR-BD01
Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc.	DPR-26, DPR-64 May 22, 2008

NEW YORK STATE'S SUPPLEMENTAL CITATION IN SUPPORT OF ADMISSION OF CONTENTION 26A

On May 14, 2008 – two weeks after the State of New York submitted its Reply to Entergy's Answer and NRC Staff's Response to New York's Supplemental Contention No.26-A (Metal Fatigue) – the NRC Staff posted on ADAMS a May 8, 2008 Summary of an April 3, 2008 telephone conference between Entergy and Staff regarding, *inter alia*, how much information NRC Staff would require Entergy to produce as part of its License Renewal Application.[1] The Summary is contained in Attachment 1 to this Supplement, and is also available at ML081190059. The May 8 Summary reveals that Entergy, with the acquiescence of Staff, does not intend to allow the details of how it will address metal fatigue issues to be made a part of this license renewal proceeding. Enclosure 1 to May 8, 2008 Summary of April 3, 2008 Telephone Conference, at pages 1 to 3.

This newly-disclosed information supplements the statements made by New York State in its May 1, 2008 Reply at the end of the first full paragraph on page 10.

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[1]The New York State Office of the Attorney General received a copy of the May 8, 2008 Summary via U.S. Mail on May 19, 2008.

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ATTACHMENT 1

NRC May 8, 2008 Summary of an
April 3, 2008 telephone conference between Entergy and NRC Staff

also available at ML081190059

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

May 8, 2008

LICENSEE: Entergy Nuclear Operations, Inc.

FACILITY: Indian Point Nuclear Generating Unit Nos. 2 and 3

SUBJECT: SUMMARY OF TELEPHONE CONFERENCE CALL HELD ON APRIL 3, 2008, BETWEEN THE U.S. NUCLEAR REGULATORY COMMISSION AND ENTERGY NUCLEAR OPERATIONS, INC., CONCERNING RESPONSES TO REQUEST FOR ADDITIONAL INFORMATION RELATED TO THE INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3, LICENSE RENEWAL APPLICATION — METAL FATIGUE, BOLTED CONNECTIONS, AND BORAFLEX

The U.S. Nuclear Regulatory Commission (NRC or the staff) and representatives of Entergy Nuclear Operations, Inc., held a telephone conference call on April 3, 2008, to discuss and clarify the staff's draft request for additional information (D-RAI) concerning the Indian Point Nuclear Generating Unit Nos. 2 and 3, license renewal application. The telephone conference call was useful in clarifying the intent of the staff's D-RAI.

Enclosure 1 provides a listing of the participants and Enclosure 2 contains a listing of the D-RAI items discussed with the applicant, including a brief description on the status of the items.

The applicant had an opportunity to comment on this summary.

Kimberly Green

Kimberly Green, Safety Project Manager
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Docket Nos. 50-247 and 50-286

Enclosures:
1. List of Participants
2. Summary of Discussion

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TELEPHONE CONFERENCE CALL
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION

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ENCLOSURE 1

DRAFT REQUEST FOR ADDITIONAL INFORMATION
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION
METAL FATIGUE

April 3, 2008

The U.S. Nuclear Regulatory Commission (NRC or the staff) and representatives of Entergy Nuclear Operations, Inc., held a telephone conference call on April 3, 2008, to discuss and clarify the following draft requests for additional information (D-RAIs) concerning the Indian Point Nuclear Generating Unit Nos. 2 and 3 license renewal application (LRA).

D-RAI 4.3.1.8-1

License Renewal Application Section 4.3.1 states "Current design basis fatigue evaluations calculate cumulative usage factors (CUFs) for components or sub-components based on design transient cycles." For CUF values listed in LRA Tables 4.3-13 and 4.3-14, please provide the methodology used with sufficient results of the fatigue analysis such that the staff can make a determination based on the guidance described in Standard Review Plan-License Renewal (SRP-LR) (NUREG-1800). Specifically, please describe the details of how environmentally assisted fatigue (EAF) is factored into the calculation of the CUF using F_{en} values.

Discussion: The applicant was uncertain as to whether the staff was requesting that they provide the evaluations or a description of evaluations. Based on the discussion with the applicant, the staff agreed to revise this question as follows. The revised question will be sent as a formal RAI.

> License renewal application (LRA) Section 4.3.1 states "Current design basis fatigue evaluations calculate cumulative usage factors (CUFs) for components or sub-components based on design transient cycles." For CUF values listed in LRA Tables 4.3-13 and 4.3-14, please describe the details of how various environmental effects are factored into the calculation of the CUF using F_{en} values.

D-RAI 4.3.1.8-2

From the review of EAF analysis of other plants, it was found that the transfer function methodology used in the EAF analysis may not provide valid results, as it is dependent on the inputs. To assist the staff in its review, please provide the EAF analysis for all the NUREG/CR-6260 locations (components) at Indian Point unless it can be demonstrated that the CUF value is within the ASME Code limit of 1.0 by using the original 40-year analysis value adjusted for 60 years and multiplied by F_{en}, which is consistent with SRP-LR and ASME Code. This analysis should be completed by using NRC-approved fatigue software and the ASME Code, Section III, Subsection NB-3200 methodology (which defines the use of six stress components to determine the stress state and thereby calculates the principal stresses and stress intensities). Justify the analysis method, the load (stress) combination, and the results of the ASME Code analysis if 2-D axis-symmetric modeling is used. In addition, the analysis should apply ASME code rules such as elastic-plastic correction factor, K_e, and stress intensities correction factor for modulus of elasticity. This analysis should be performed without the use of the transfer function method.

Discussion: The applicant wanted clarification on the staff's request. The applicant pointed out that the request is a new staff position and that for previous plants, the staff has not requested the analyses to be provided and has accepted a commitment to perform the analyses two years prior to entering the period of extended operation as part of the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii). Subsequent to the telephone conference, the staff determined that no additional information is needed at this time. Therefore, a formal RAI will not be issued at this time.

D-RAI 4.3.1.8-3

SRP-LR Section 4.3.2.1.1.3 provides the basis for the staff acceptance of an aging management program to address environmental fatigue. It states, "[T]he staff has evaluated a program for monitoring and tracking the number of critical thermal and pressure transients for the selected reactor coolant system components. The staff has determined that this program is an acceptable aging management program to address metal fatigue of the reactor coolant system components according to 10 CFR 54.21(c)(1)(iii)." The staff is unable to determine if the Fatigue Monitoring Program of IP2 and IP3 contain sufficient details to satisfy this criterion, based on the NA items listed in LRA Tables 4.3-13 and 4.3-14. Please provide adequate details of the Fatigue Monitoring Program, specifically the fatigue analysis used in determining the CUF values for the NA locations and how IPEC plans to proceed in monitoring the locations of Tables 4.3-13 and 4.3-14 during the period of extended operation.

Discussion: The applicant wanted clarification on what the staff is requesting. Based on the discussion with the applicant, the staff agreed to revise this question as follows. The revised question will be sent as a formal RAI.

> Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR) Section 4.3.2.1.1.3 provides the basis for the staff acceptance of an aging management program to address environmental fatigue. It states, "[t]he staff has evaluated a program for monitoring and tracking the number of critical thermal and pressure transients for the selected reactor coolant system components. The staff has determined that this program is an acceptable aging management program to address metal fatigue of the reactor coolant system components according to 10 CFR 54.21(c)(1)(iii)." The staff is unable to determine if the Fatigue Monitoring Program for Indian Point 2 and Indian Point 3 contains sufficient details to satisfy this criterion. Please provide adequate details of the Fatigue Monitoring Program such that the staff can make a determination based on the criterion set forth in SRP-LR Section 4.3.2.1.1.3. Also, please explain in detail the corrective actions and the frequency that such actions will be taken so that the acceptance criteria will not be exceeded in the period of extended operation. (This RAI will be renumbered as RAI 4.3.1.8-2.)

D-RAI 4.3.1.8-4

Section B.1.12 of the LRA amendment, dated January 22, 2008, states, "If ongoing monitoring indicates the potential for a condition outside that analyzed above, IPEC may perform further reanalysis of the identified configuration using established configuration management processes as described above." Please explain in detail what is meant by the phrase "using established configuration management processes." Also, please explain in detail the corrective actions and the frequency that such actions will be taken so the acceptance criteria will not be exceeded in the period of extended operation.

Discussion: The applicant stated that it was unclear about the staff's request regarding "configuration management processes." In a subsequent call, the applicant explained that the configuration management processes referred to are those governed by its 10 CFR Part 50, Appendix B Quality Assurance program, and include design input verification and independent reviews which ensure that valid assumptions, transients, cycles, external loadings, analysis methods, and environmental fatigue life correction factors will be used in the fatigue analyses. Therefore, this portion of question is withdrawn and will not be sent as a formal RAI. The portion of the request that deals with corrective actions will be added to RAI 4.3.1.8-2 (as renumbered).

Non-EQ Bolted Cable Connection AMP

D-RAI 3.0.3.3.6-1

With regard to Indian Point Aging Management Program (AMP) B.1.22, "Non-EQ Bolted Cable Connection Program," the license renewal application states that inspection methods may include thermography, contact resistance testing, or other appropriate methods including visual, based on plant configuration and industry guidance. In Generic Aging Lessons Learned (GALL) AMP XI.E6, the staff recommends thermography, contact resistance testing, or other appropriate methods based on plant configuration and industry guidance for detecting loss of preload or bolt loosening. In the case where visual inspection will be the only method used, provide a technical basis of how this will be sufficient to detect loss of preload or loosening of bolted connections.

Discussion: The applicant stated that this question is similar to an audit question that has been answered and subsequently discussed during two telephone conferences. This issue is being reviewed by the Division of Engineering and, therefore, is withdrawn at this time. However, when the staff has reached a determination, a formal RAI may be issued at such time.

Boraflex AMP

D-RAI 3.0.3.2.3-1

Indian Point 2 Updated Final Safety Analysis Report, Revision 20, dated 2006, Section 14.2.1 on page 55 of 218, states in part that:

> "Northeast Technology Corporation report NET-173-01 and NET-171-02 are based on conservative projections of amount of boraflex absorber panel degradation assumed in each sub-region. These projections are valid through the end of the year 2006."

Please confirm that the Boraflex neutron absorber panels in the Indian Point Unit 2 spent fuel pool have been re-evaluated for service through the end of the current licensing period. Also, please discuss the plans for updating the Boraflex analysis during the period of extended operation.

Discussion: The applicant indicated that the question is clear. This D-RAI will be sent as a formal RAI.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY LICENSING BOARD

---x

In re:

License Renewal Application Submitted by

Entergy Nuclear Indian Point 2, LLC,
Entergy Nuclear Indian Point 3, LLC, and
Entergy Nuclear Operations, Inc.

---x

Docket Nos. 50-247-LR and 50-286-LR

ASLBP No. 07-858-03-LR-BD01

DPR-26, DPR-64

CERTIFICATE OF SERVICE

Pursuant to 28 U.S.C. § 1746 Teresa Fountain hereby declares:

I am over 18 years old and am an employee in the New York State Office of the Attorney General.

I hereby certify that on May 22, 2008, copies of "The State of New York's Supplemental Citation In Support of Contention 26A" were served upon the following persons via electronic mail and by deposit in the U.S. Postal Service with first class postage:

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I declare under penalty of perjury that the foregoing is true and correct.

Executed on:

this 22nd day of May 2008
Albany, New York

Teresa Fountain

Teresa Fountain

Entergy	CONDITION REPORT	CR-VTY-2007-02133

Originator: Fales,Neil
Originator Group: Eng P&C Codes Staff
Supervisor Name: Lukens,Larry D
Discovered Date: 05/28/2007 17:06

Originator Phone: 8024513057
Operability Required: Y
Reportability Required: Y
Initiated Date: 05/28/2007 17:11

Condition Description:
Steam Dryer Inspection Indications

During RFO26 reactor vessel inspections, linear indications on the Steam Dryer Interior Vertical Weld HB-V04 were identified by General Electric. Most of these indications were previously identified in RFO25 with no discernable changes noted in RFO26. One new relevant indication was observed of similar appearance, orientation and size as those previously seen. These were documented via GE's process by INR-IVVI-VYR26-07-10. See attached GE INR's for details.

Immediate Action Description:
Notified Supervisor and generated CR.

Suggested Action Description:
The new indication will need to be evaluated.

EQUIPMENT:

Tag Name	Tag Suffix Name	Component Code	Process System Code
STEAM-DRYER	REACTOR	MR=Y	NB

TRENDING (For Reference Purposes Only):

Trend Type	Trend Code
KEYWORDS	KW-PRE-SCREENED FOR MRFF
INPO BINNING	ER1
KEYWORDS	KW-ISI
REPORT WEIGHT	1
EM	ESPC
HEP FACTOR	E

Attachments:
Condition Description
GE INR 10

Entergy	ADMIN	CR-VTY-2007-02133

Initiated Date: 5/28/2007 17:11 **Owner Group :** Eng P&C Codes Mgmt

Current Contact: vw

Current Significance: C - INVEST & CORRECT

Closed by: Taylor,James M 6/18/2007 16:06

Summary Description:

Steam Dryer Inspection Indications

During RFO26 reactor vessel inspections, linear indications on the Steam Dryer Interior Vertical Weld HB-V04 were identified by General Electric. Most of these indications were previously identified in RFO25 with no discernable changes noted in RFO26. One new relevant indication was observed of similar appearance, orientation and size as those previously seen. These were documented via GE's process by INR-IVVI-VYR26-07-10. See attached GE INR's for details.

Remarks Description:

Closure Description:

CR closure review performed.

Attachment Header

Document Name:

untitled

Document Location

Condition Description

Attach Title:

GE INR 10

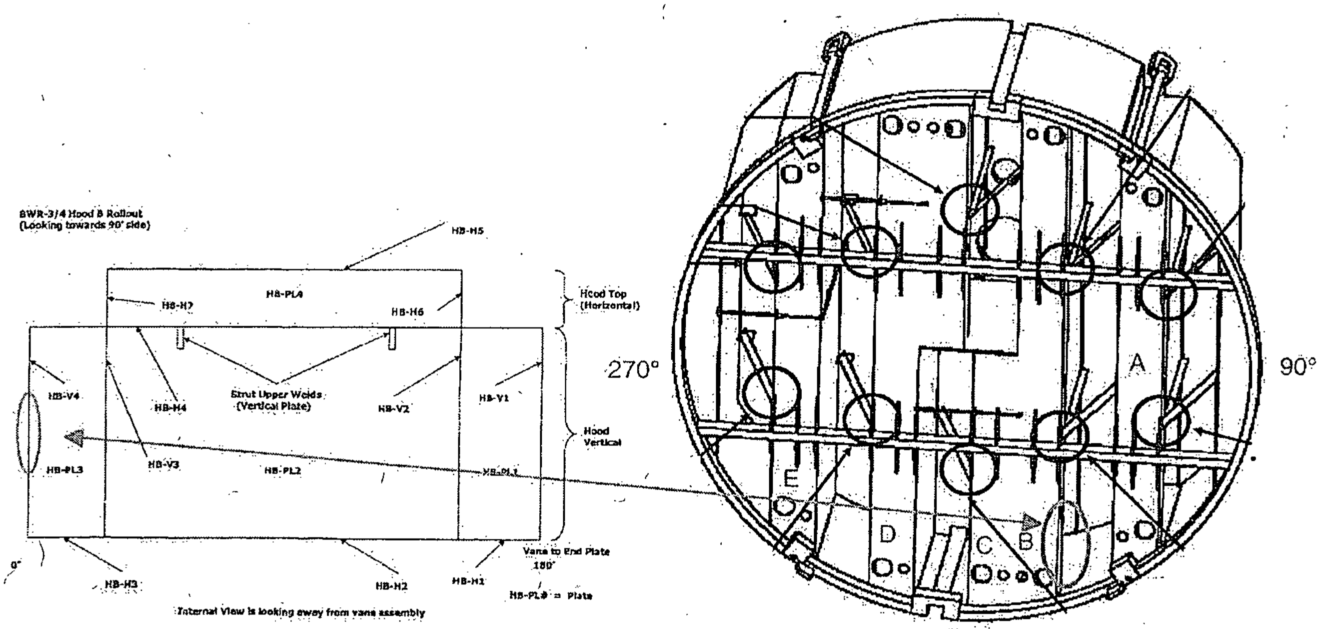
INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report

Plant / Unit	Component Description	Reference(s)
Vermont Yankee RFO26 Spring 2007	*Steam Dryer Interior Vertical Weld HB-V04*	DVD DISK IVVI-VYR26-07-58 Title 4 RFO-25 IVVI Report INF # 002.

Background

During the Vermont Yankee 2007 refueling outage, in accordance with the Vermont Yankee VT-VMY-204V10 Rev 2 Procedure, the Steam Dryer was inspected. The dryer inspection included inspection of the Steam Dryer interior welds and components. These inspections were done with GE's Fire Fly ROV with color camera. During the inspection of the HB-V04 weld (Dryer Unit Hood End Panel to HB-PL3 Plate weld), relevant linear indications were observed in the heat affected zone on the Dryer Unit side of the weld. Most of these linear indications were previously seen in RFO-25, Reference INF # 002. When comparing this outage with last outage, one new relevant indication is seen (3rd indication) of similar appearance, orientation and size as those previously seen; one indication was not seen (RFO25: 3th indication). No discernible change was noted in those indications which correlates to those of RFO26. See attached 2007 photos and sketches.



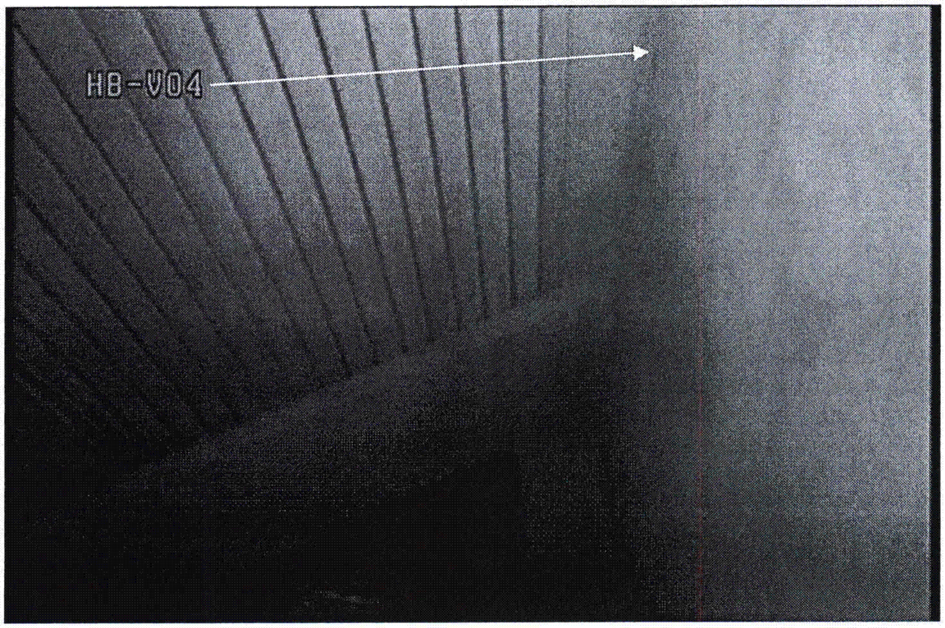
Sketch on the left shows the weld map rollout   The sketch on the right shows a bottom view of the dryer.

Prepared by: Dick Hooper   Date: *05/27/07*   Reviewed by: Rodney Drazich   Date: *05/27/07*

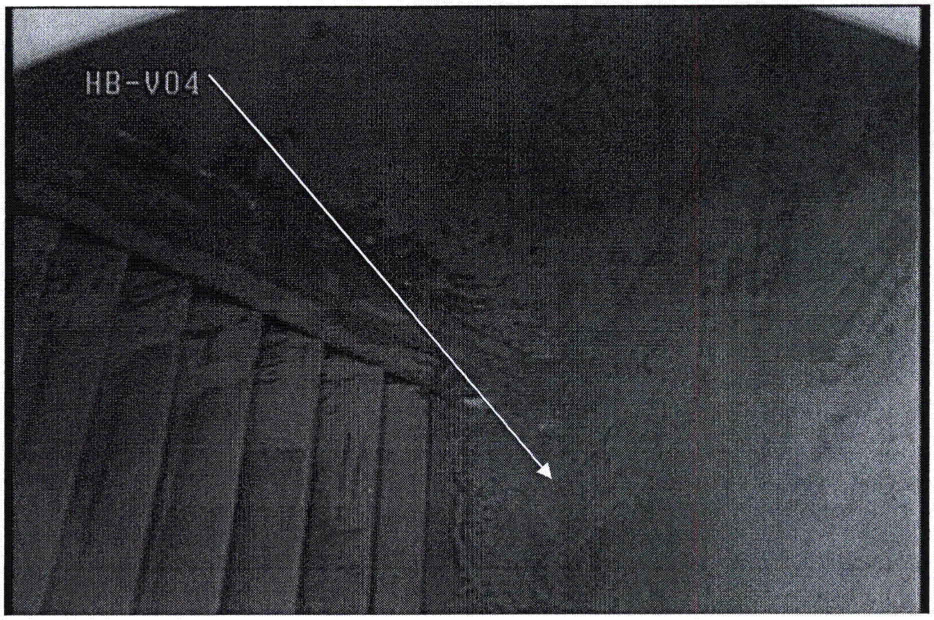
Utility Review By: R. Kadu   Date: 5/27/07

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report



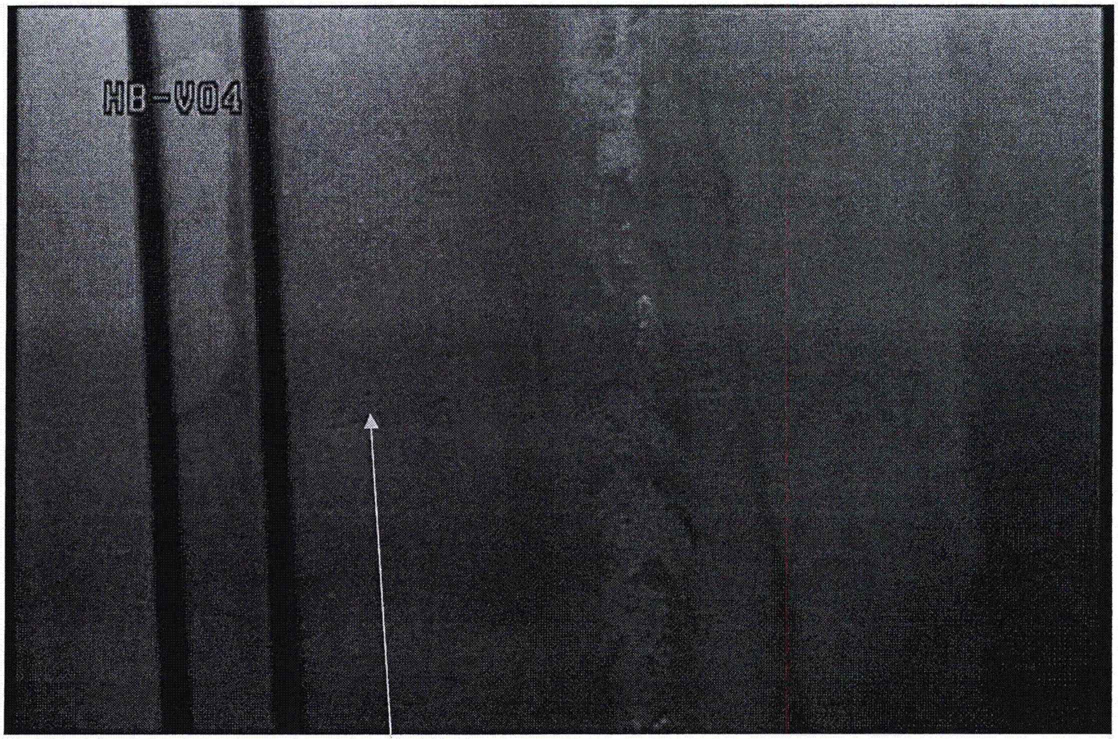
This 2007 photo shows the interior of the dryer and the location of HB-V04 vertical weld.



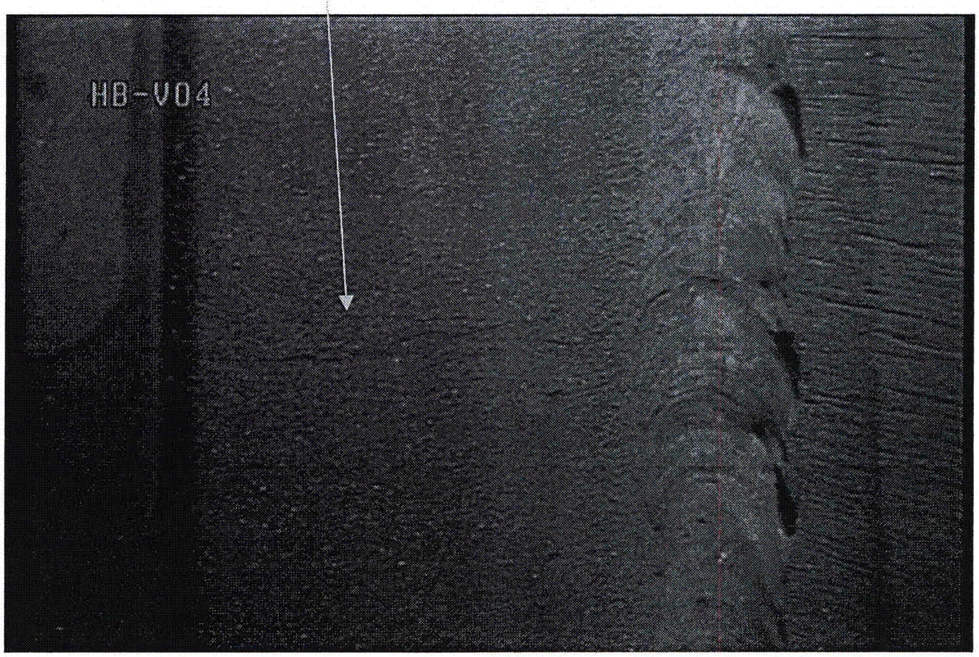
This 2007 photo shows the top of the vane bank (on the left) and the end panel (on the right) and the vertical weld in the center

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report



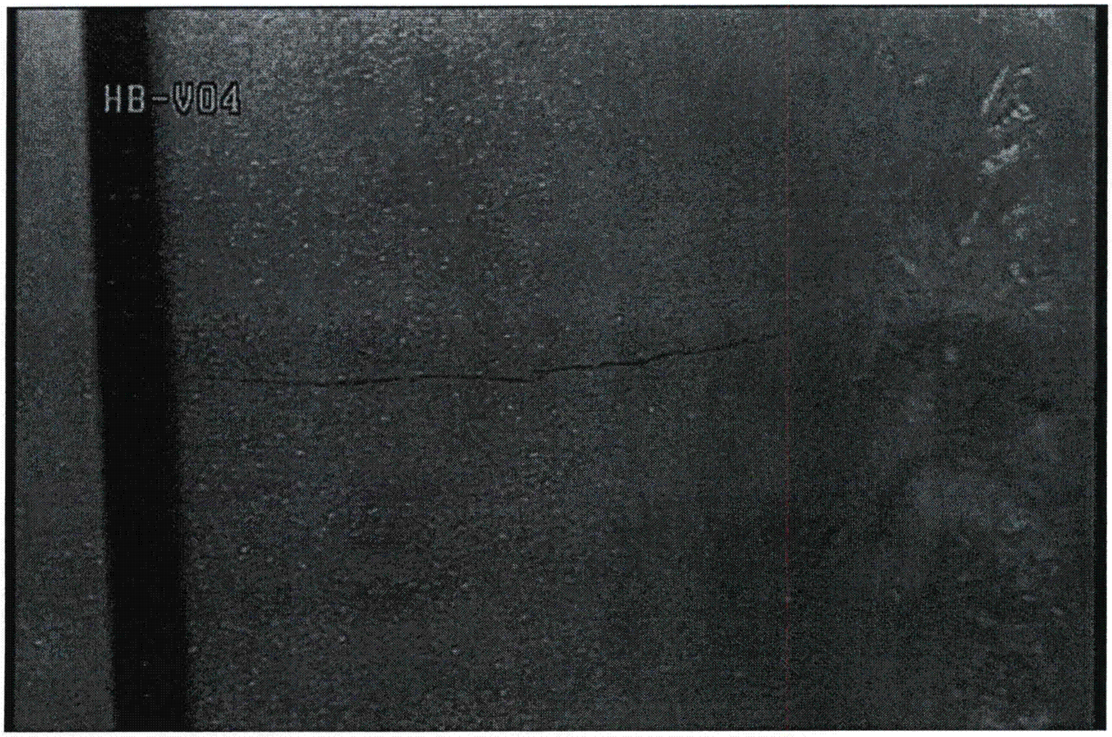
This 2007 photo is of the 1st indication from top down (Correlates to RFO25: 1st indication).



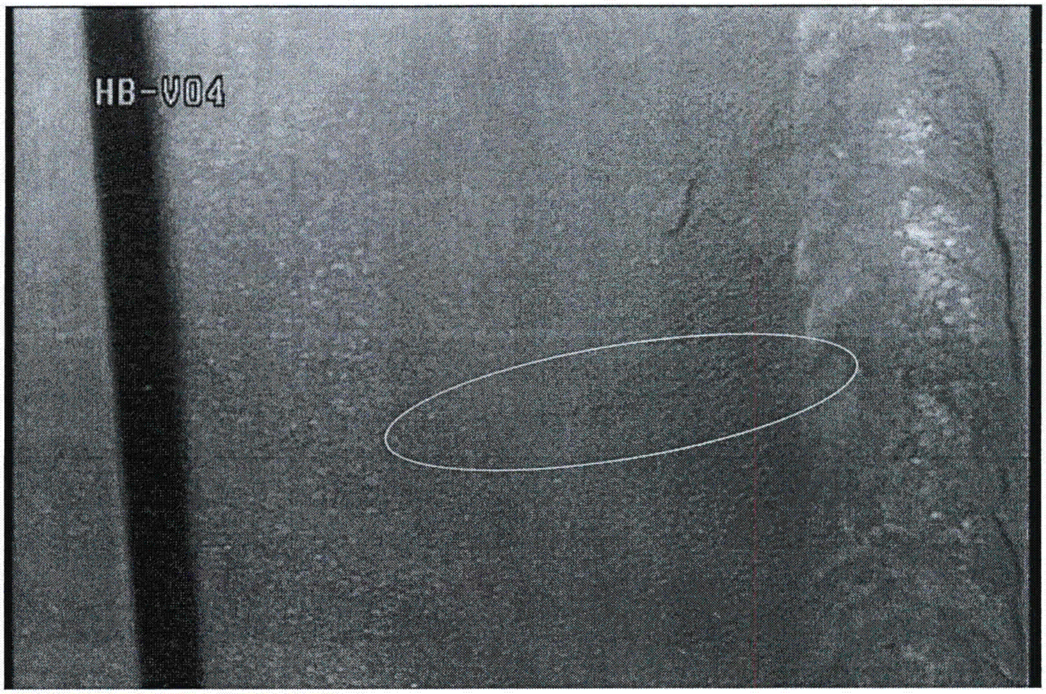
This 2007photo is a close-up of the 1st indication (Correlates to RFO25: 1st indication).

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report



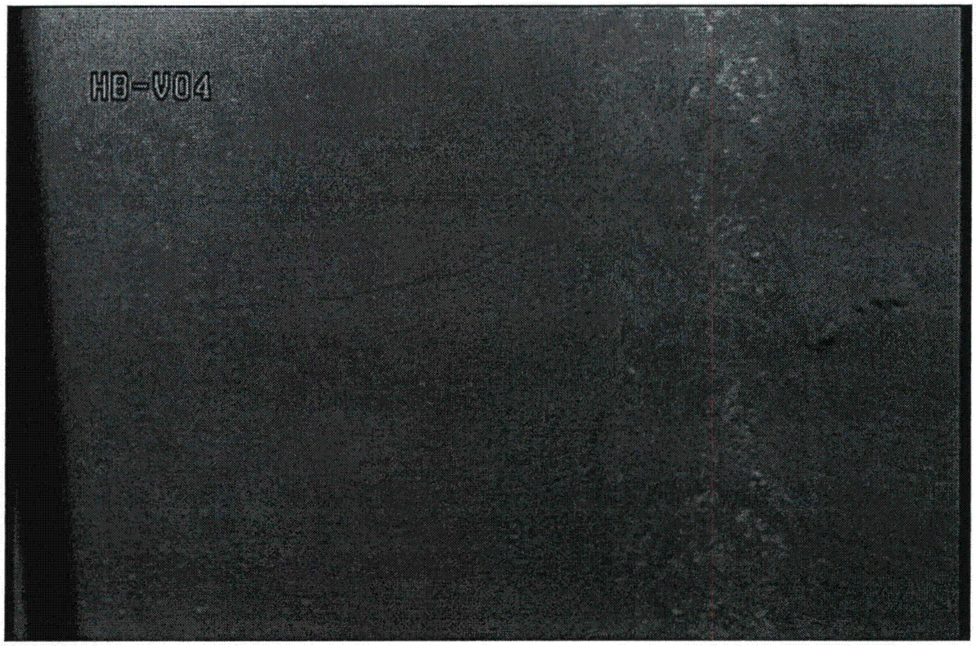
This 2007 photo is the 2nd indication (Correlates to RFO25: 2nd indication).



This is a 2007 photo of the 3rd indication and is a new RFO26 indication.

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report

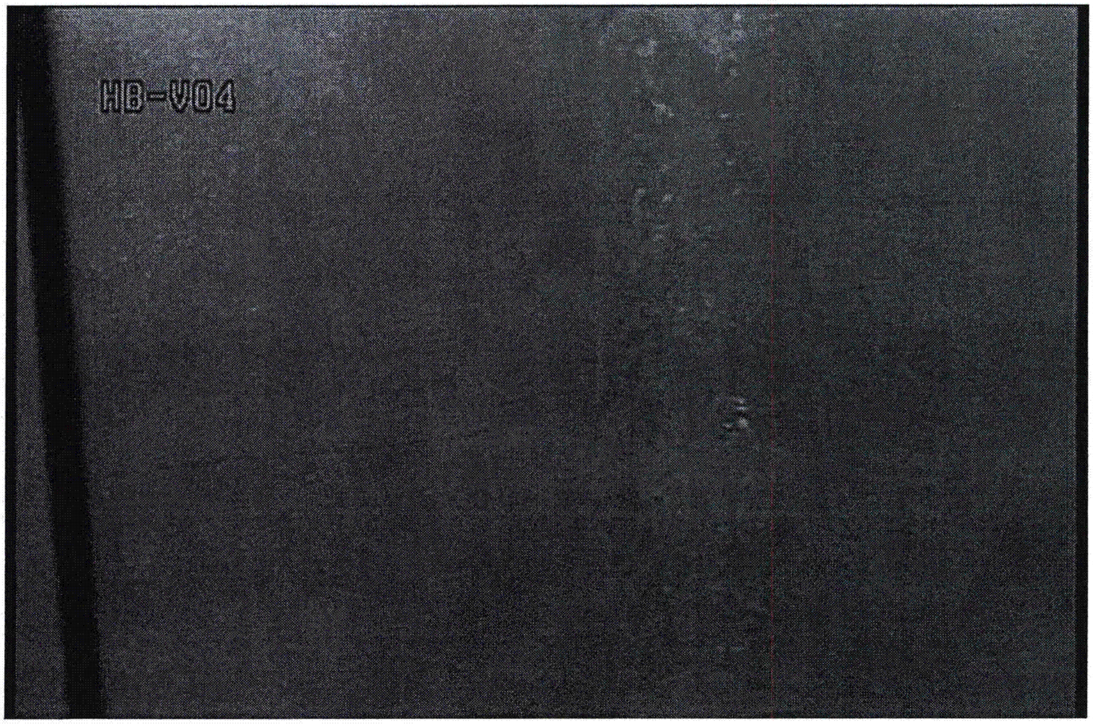


This is a 2007 photo of the 4th indication (Correlates to RFO25: 3rd indication)

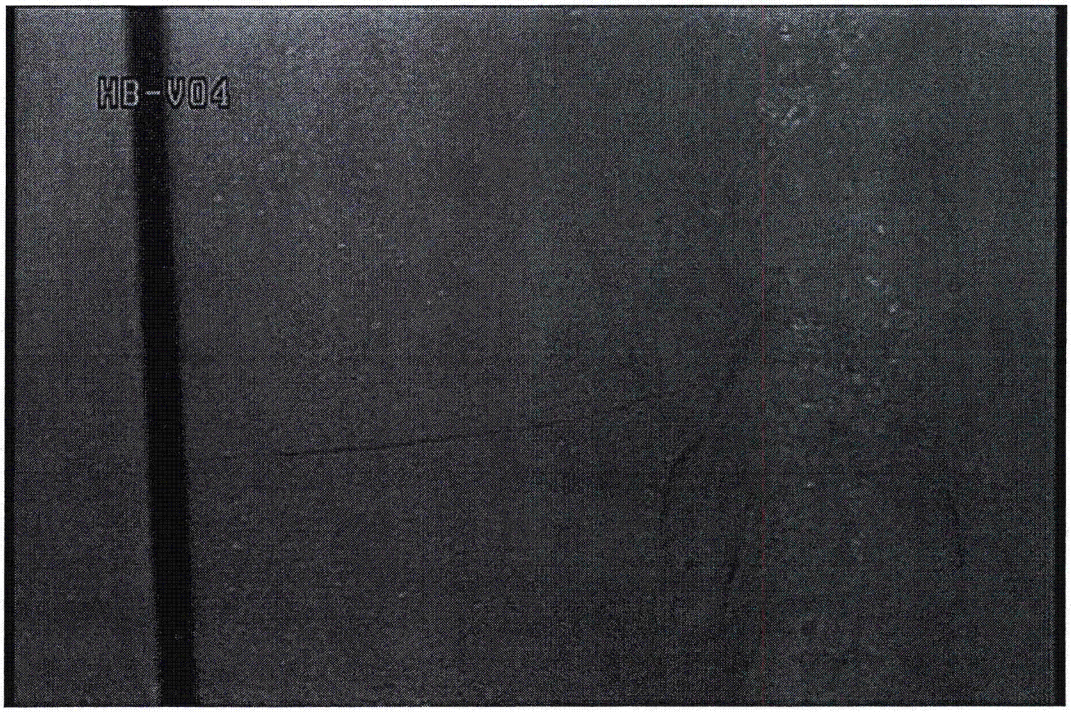
This is a 2007 photo of the 5th indication (Correlates to RFO25: 4th indication).

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report



This is a 2007 photo of the 6th indication (Correlates to RFO25: 5th indication).

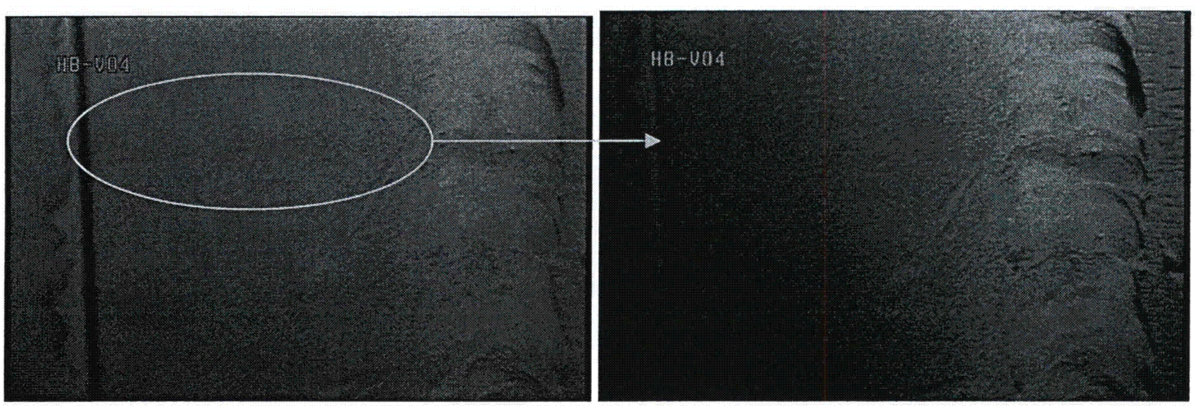


This is a 2007 photo of the 7th indication (Correlates to RFO25: 6th indication).

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report

This is a 2007 photo of the 8th indication (Correlates to RFO25: 7th indication).

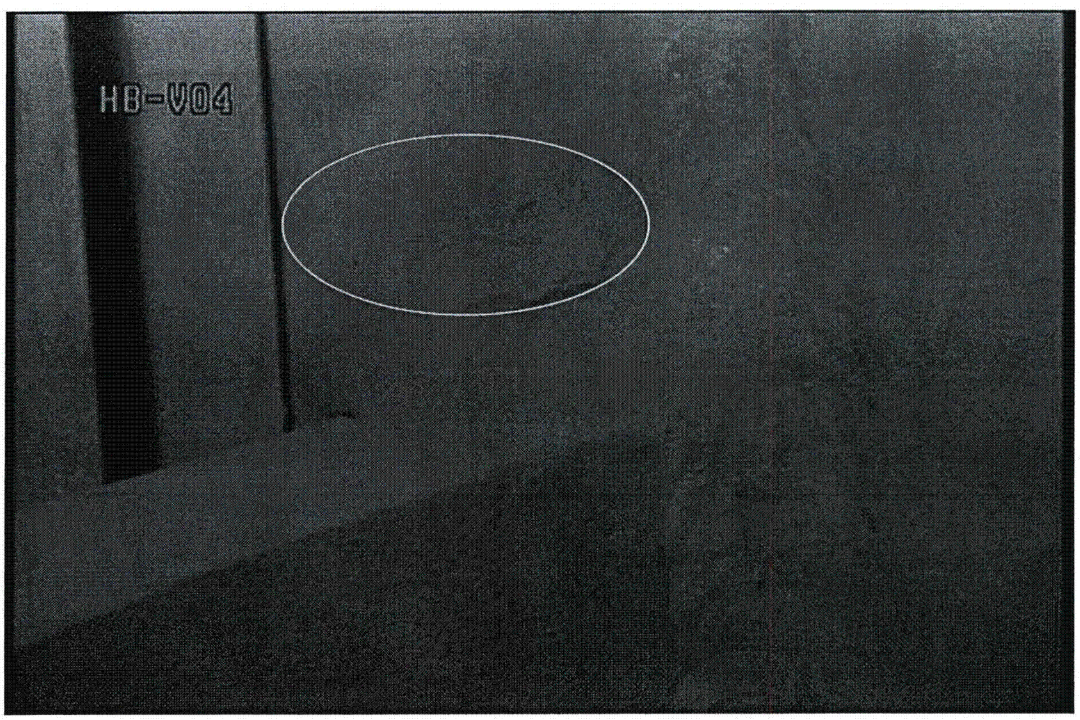


These 2007 photos show a linear indication and change of lighting and show a non-relevant indication (Correlates to RFO25: 9th indication).

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report

This is a 2007 photo of the 9th indication (Correlates to RFO25: 10th indication).



This is a 2007 photo of the bottom weld area and crud line.

Entergy	OPERABILITY	CR-VTY-2007-02133

OperabilityVersion: 1

Operability Code: EQUIPMENT FUNCTIONAL

Immediate Report Code: NOT REPORTABLE

Performed By: Brooks,James C 05/29/2007 21:07

Approved By: Faupel,Robert F 05/30/2007 00:30

Operability Description:

Currently the plant is shutdown with the bolt in place. The bolt has one crimp fully engaged preventing the bolt from backing out. The need for having both crimps fully engaged will have to be evaluated prior to startup.

Approval Comments:

Entergy	ASSIGNMENTS	CR-VTY-2007-02133

Version: 2

Significance Code: C - INVEST & CORRECT

Classification Code: C

Owner Group: Eng P&C Codes Mgmt

Performed By: Wren,Vedrana 05/30/2007 13:04

Assignment Description:

Entergy	**ASSIGNMENTS**	**CR-VTY-2007-02133**

Version: 1

Significance Code: C - INVEST & CORRECT

Classification Code: C

Owner Group: Eng P&C Codes Mgmt

Performed By: Lukens,Larry D 05/29/2007 04:46

Assignment Description:

self identified
outage constraint

Entergy	REPORTABILITY	CR-VTY-2007-02133

Reportability Version: 1

Report Number:

Report Code: NOT REPORTABLE

Boilerplate Code: NOT REPORTABLE

Performed By : Devincentis,James M 05/29/2007 08:09

Reportability Description:

Not reportable - This condition does not meet the Reportability screening criteria contained in AP0010 or AP0156. The Steam Dryer is NNS and performs no safety releted functions. VY has a commitment to provide the results of the steam dryer inspections to the NRC following startup.

Entergy	**CORRECTIVE ACTION**	**CR-VTY-2007-02133**

CA Number: 1

	Group	Name
Assigned By:	CRG/CARB/OSRC	
Assigned To:	Eng P&C Codes Mgmt	Lukens,Larry D
Subassigned To :	Eng P&C Codes Staff	Fales,Neil

Originated By:	Wren,Vedrana	5/30/2007 13:00:53
Performed By:	Lukens,Larry D	6/15/2007 13:17:25
Subperformed By:	Fales,Neil	6/15/2007 11:49:49
Approved By:		
Closed By:	Taylor,James M	6/18/2007 16:02:38

Current Due Date: 06/28/2007 **Initial Due Date:** 06/28/2007

CA Type: DISP - CA

Plant Constraint: 0 NONE

CA Description:

C - INVEST & CORRECT (Review CR for full details)
□The CRG has initially classified this CR as "C" INVEST & CORRECT
□
□Per the CRG, Perform an Investigation of the issues identified in this CR and determine if additional actions are
□required within 30 days.
□
□Ensure all Screening Comments have been addressed in the investigation - (CR assignment tab)
□Develop adequate corrective actions and issue CAs. (Due Dates per LI 102 Attachment 9.4)
□LT CAs Require Approval from Site VP/ GMPO or Director prior to initiating. Completion of Attachment 9.9 LTCA
□Classification Form is required.

Response:

Approved. No additional corrective action required. Therefore, this CR may be closed. LI-102 Closure Statements follow:

CR CLOSURE STATEMENTS FROM LI-102:

o□The root cause or apparent cause is valid. VERIFIED
o□The specific condition is corrected or resolved. VERIFIED
o□Overall plant safety is not inadvertently degraded. VERIFIED
o□Generic implications of the identified condition are considered, as appropriate. VERIFIED
o□Actions were taken to preclude repetition, as appropriate. VERIFIED
o□Any potential operability or reportability issues identified during the resolution of the condition have been appropriately addressed. VERIFIED
o□All corrective action items are completed. VERIFIED
o□Effectiveness Reviews have been initiated via use of Learning Organization CR, when applicable. VERIFIED

Subresponse :

The new indication was evaluated by Code Programs, see the attached document. The evaluation accepts the indication as is with no repair required. The steam dryer will be inspected per the same scope in RFO27 and RFO28 per letter BVY 04-097, therefore the area of this indication will be inspected again during the next two outages.

Neil Fales 6/15/07

Closure Comments:

Entergy	**CORRECTIVE ACTION**	**CR-VTY-2007-02133**

Attachments:

Subresponse Description
Evaluation

Attachment Header

Document Name:

untitled

Document Location

Subresponse Description

Attach Title:

Evaluation

Engineering Report No. VY-RPT-07-00011 Rev 2

Entergy

ENTERGY NUCLEAR
Engineering Report Cover Sheet

Engineering Report Title:
EVALUATION OF NEW RFO26 STEAM DRYER INDICATION

Engineering Report Type:

New ☒ Revision ☐ Cancelled ☐ Superseded ☐

Applicable Site

IP1	☐	IP2	☐	IP3	☐	JAF	☐	PNPS	☐	VY	☒	WPO	☐
ANO1	☐	ANO2	☐	ECH	☐	GGNS	☐	RBS	☐	WF3	☐		

DRN No. ☐N/A; ☒EC 1772

Report Origin: ☒ Entergy ☐ Vendor
Vendor Document No.:________

Quality-Related: ☒ Yes ☐ No

Prepared by: Neil Fales/ N. F. Date: 6/15/07
Responsible Engineer (Print Name/Sign)

Design Verified/ N/A Date:
Design Verifier (if required) (Print Name/Sign)

Reviewed by: Scott Goodwin/ S. D. Goodwin Date: 6-15-07
Reviewer (Print Name/Sign)

Reviewed by*: N/A Date:
ANII (if required) (Print Name/Sign)

Approved by: Larry Lukens/ [signature] Date: 6/15/07
Supervisor (Print Name/Sign)

*: For ASME Section XI Code Program plans per ENN-DC-120, if require

Evaluation of Steam Dryer Indication

Introduction

During RFO26 steam dryer visual inspections, flaw indications were reported in the dryer end plates for the internal vane assemblies. Most of these indications were previously identified in RFO25 and were evaluated by GE as being acceptable to leave as is per Reference 11. The intent of this paper is to evaluate one new indication identified during RFO26 and determine whether it should be accepted as is.

Discussion

One new indication was found adjacent to weld HB-V04, located on bank B at the 0° end and is labeled as the 3rd indication on INR-IVVI-VYR26-07-10 Rev.1 (Reference 2). This indication is of similar appearance, orientation and size as those previously seen. Because of this it is being treated similar to those indications identified in RFO25. The remainder of indications on the steam dryer listed as References 1-10 were previously identified and show no signs of growth. These indications are acceptable to leave as is per GE evaluation GENE-0000-0047-2767 (Reference 11) performed in RFO25. Therefore, the one new indication described above is the only one requiring an evaluation.

It should be mentioned that not all indications identified in RFO25 were re-identified in RFO26. The reasons for this vary, but can be the limitations of the equipment, crud layers masking the surface of the indication or the technique of different examiners.

Evaluation of Indications

GE's evaluation in RFO25 cites IGSCC as being the likely cause of most of the indications previously observed. This is based on the jagged appearance and location in the weld heat affected zone (HAZ). The unit end plates may have cold work resulting from cold forming. Cold working Type 304 material can promote initiation of stress corrosion cracks when exposed to the BWR environment. The dryer unit end plates are located in the dryer interior and are not subjected to any direct main steam line acoustic loading. Continued growth is unlikely because all of these indications appear to have stopped without propagating into the vertical weld; this is indicative of IGSCC behavior as opposed to fatigue, since weld material is more resistant to IGSCC. The flanges have experienced a near infinite number of fluctuating load cycles and if fatigue driven, more significant cracking is likely to have occurred after many years of operation. IGSCC in steam dryers has been typically limited in depth and length since in many cases it is caused by cold work or weld induced residual stress.

The dyer unit end plate, with the indication, is securely attached and captured within the structure of the steam dryer bank assembly. The vertical edges of these end plates are attached to the dryer assembly with 3/16" fillet welds, each weld approximately 48" long.

There were no relevant indications reported in these vertical welds. The geometric configuration of the unit end plates is such that the steam dryer assembly mechanically captures the upper and lower edges. The reported horizontal indications were seen in the inlet side end plate flange. The vanes prevent inspection of the central end plate surface, but inspection of the outlet side end plate flanges at both locations found no indications. If it is postulated that the end plate horizontal indications propagate across the entire 8.75" unit end plate width including both the inlet and outlet side flange, such full width, through-thickness cracks would have no structural impact. Nor is there any concern for loose parts. The separated end plate sections are still attached and will continue to function.

Safety

The steam dryer assembly has no safety function. See BWRVIP-06A for additional discussion of steam dryer assembly safety. The flaw indications reported in the steam dryer INR's from RFO26 will not likely result in any lost parts at operating conditions. Therefore, there is no safety concern with continued operation with the Reference 1-10 indications left as is.

Conclusions and Recommendations

The dryer unit end plates flaw assessment is based on the following factors: (1) it is a highly redundant structure and there is no structural consequence of the cracking and (2) postulated significant flaw extension leading to the flaw reaching the full section of the channel geometry would not create the opportunity for loose parts. Field experience supports this as-is operation decision in the context that the indications will be re-inspected at the next outage. It is recommended that the new visual indication given in Reference 2 be accepted as is. Repair is not recommended.

References

1. GE INR-IVVI-VYR26-07-09 Rev. 1
2. GE INR-IVVI-VYR26-07-10 Rev. 1
3. GE INR-IVVI-VYR26-07-11
4. GE INR-IVVI-VYR26-07-12
5. GE INR-IVVI-VYR26-07-13
6. GE INR-IVVI-VYR26-07-14
7. GE INR-IVVI-VYR26-07-15
8. GE INR-IVVI-VYR26-07-16
9. GE INR-IVVI-VYR26-07-18
10. GE INR-IVVI-VYR26-07-19
11. GENE-0000-0047-2767

Entergy	**CORRECTIVE ACTION**	**CR-VTY-2007-02133**

CA Number: 2

	Group	Name
Assigned By:	Constraint Group	
Assigned To:	Eng P&C Codes Mgmt	Lukens,Larry D
Subassigned To :	Eng P&C Codes Staff	Fales,Neil

Originated By:	Wren,Vedrana	5/30/2007 13:02:05
Performed By:	Corbett,Patrick B	6/1/2007 17:50:21
Subperformed By:	Fales,Neil	6/1/2007 16:58:55
Approved By:		
Closed By:	Wanczyk,Robert J	6/1/2007 17:54:13

Current Due Date: 06/01/2007 **Initial Due Date:** 06/01/2007

CA Type: ACTION

Plant Constraint: 2 STARTUP/HOTSTANDBY

CA Description:

Address Startup Constraint-due 6/1-Disposition and evaluate

Response:

approve

Subresponse :

The plant can start up with the dryer indications left as is. The new dryer indication is of the same appearance, orientation and size as those previously observed. Since this new indication is located in the heat affected zone and is consistant with the other indications, this is most likely caused by IGSCC. This is consistant with the evaluations by GE. See the INR and evaluation provided.

Neil Fales 6/1/07

Closure Comments:

Attachments:

Subresponse Description
Evaluation

Subresponse Description
GE INR 10

Attachment Header

Document Name:

untitled

Document Location

Subresponse Description

Attach Title:

Evaluation

Evaluation of Steam Dryer Indications

Introduction

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Conclusions and Recommendations

The dryer unit end plates flaw assessment is based on the following factors: (1) it is a highly redundant structure and there is no structural consequence of the cracking and (2) postulated significant flaw extension leading to the flaw reaching the full section of the channel geometry would not create the opportunity for loose parts. Field experience supports this as-is operation decision in the context that the indications will be re-inspected at the next outage. It is recommended that the new visual indication given in Reference 2 be accepted as is. Repair is not recommended.

References

1. GE INR-IVVI-VYR26-07-09 Rev. 1
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5. GE INR-IVVI-VYR26-07-13
6. GE INR-IVVI-VYR26-07-14
7. GE INR-IVVI-VYR26-07-15
8. GE INR-IVVI-VYR26-07-16
9. GE INR-IVVI-VYR26-07-18
10. GE INR-IVVI-VYR26-07-19
11. GENE-0000-0047-2767

Attachment Header

Document Name:

untitled

Document Location

Subresponse Description

Attach Title:

GE INR 10

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

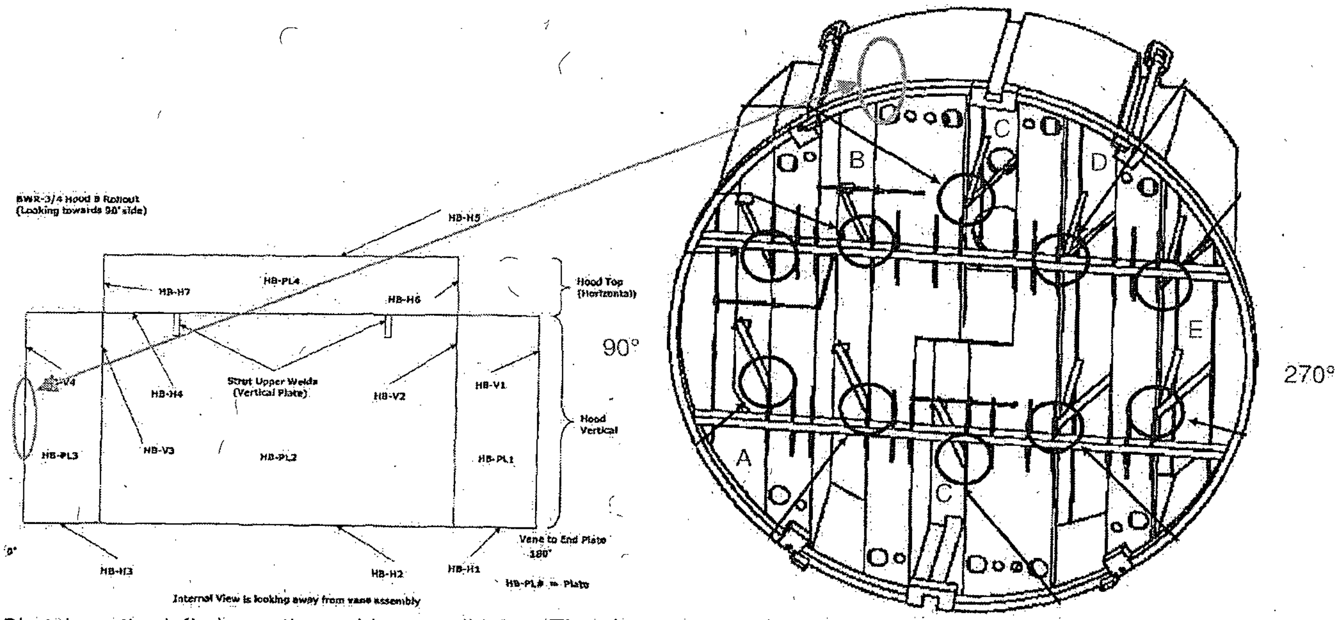
Indication Notification Report

Plant / Unit	Component Description	Reference(s)
Vermont Yankee *RFO26 Spring 2007*	*Steam Dryer* *Interior Vertical Weld* *HB-V04*	DVD DISK IVVI-VYR26-07-58 Title 4 RFO-25 IVVI Report INF # 002.

Background

Revision 1: Incorporates photos from RFO-25 and corrects the sketch.

During the Vermont Yankee 2007 refueling outage, in accordance with the Vermont Yankee VT-VMY-204V10 Rev 2 Procedure, the Steam Dryer was inspected. The dryer inspection included inspection of the Steam Dryer interior welds and components. These inspections were done with GE's Fire Fly ROV with color camera. During the inspection of the HB-V04 weld (Dryer Unit End Panel to HB-PL3 Plate weld), relevant linear indications were observed in the heat affected zone on the Dryer Unit side of the weld. Most of these linear indications were previously seen in RFO-25, Reference INF # 002. When comparing this outage with last outage, one new relevant indication is seen (3rd indication) of similar appearance, orientation and size as those previously seen; one indication was not seen (RFO25: 8 th indication). No discernible change was noted for those indications which correlates to those of RFO26. See attached 2007 photos and sketches.



Sketch on the left shows the weld map rollout The sketch on the right shows a bottom view of the dryer.

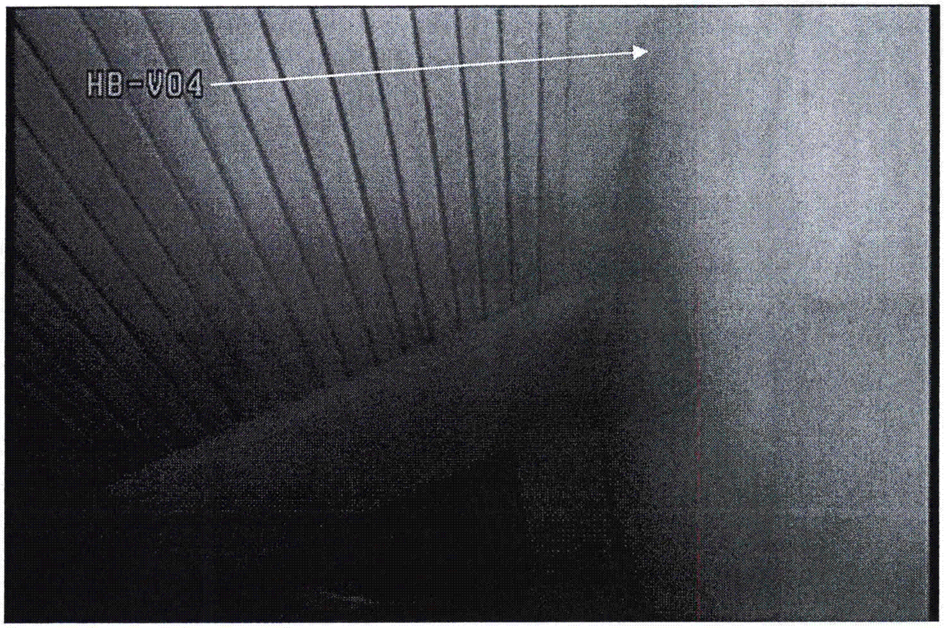
Prepared by: Dick Hooper Date: *05/31/07* Reviewed by: Rodney Drazich Date: *05/31/07*

Utility Review By: Mike Rose Date: 05/31/07

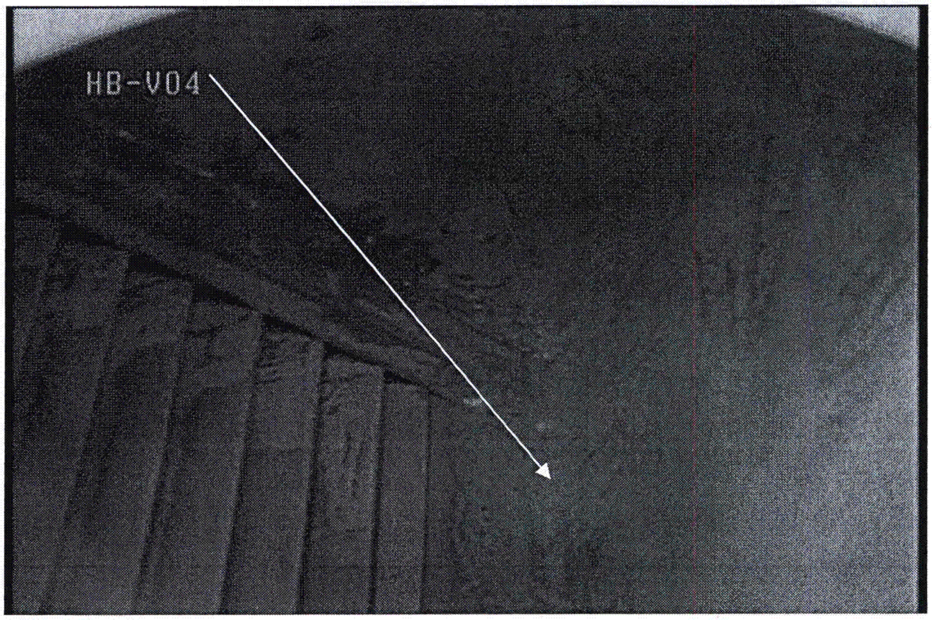
M. Rose

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

Indication Notification Report



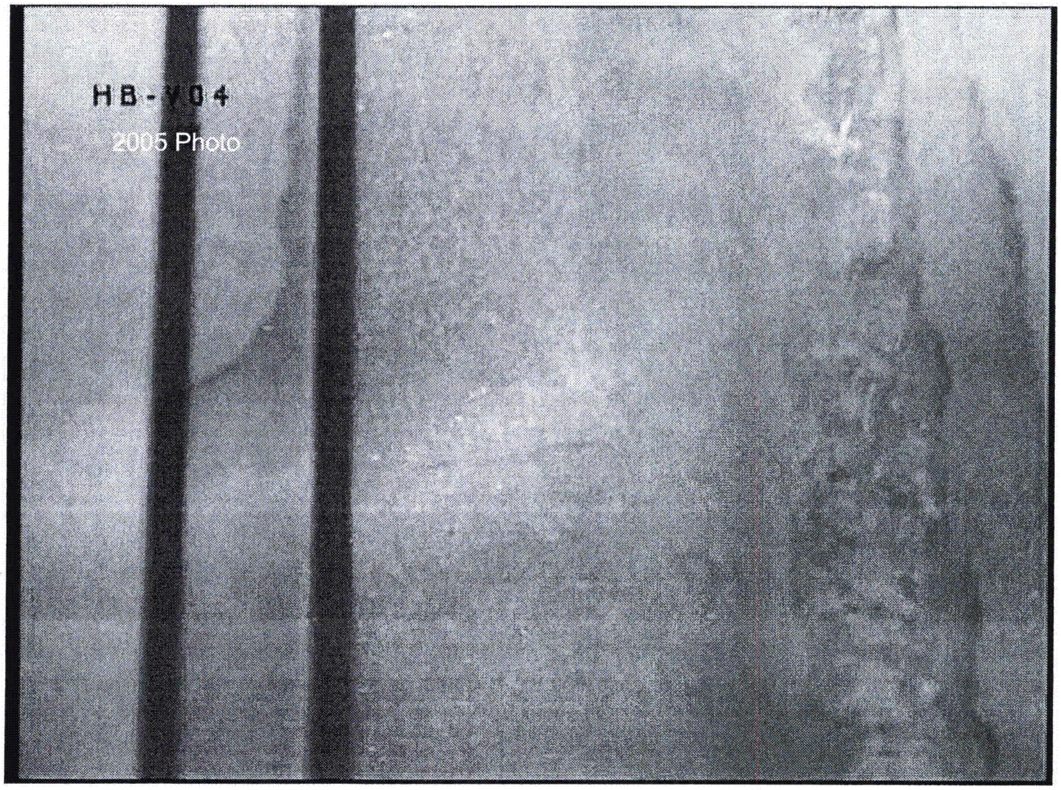
This 2007 photo shows the interior of the dryer and the location of HB-V04 vertical weld.

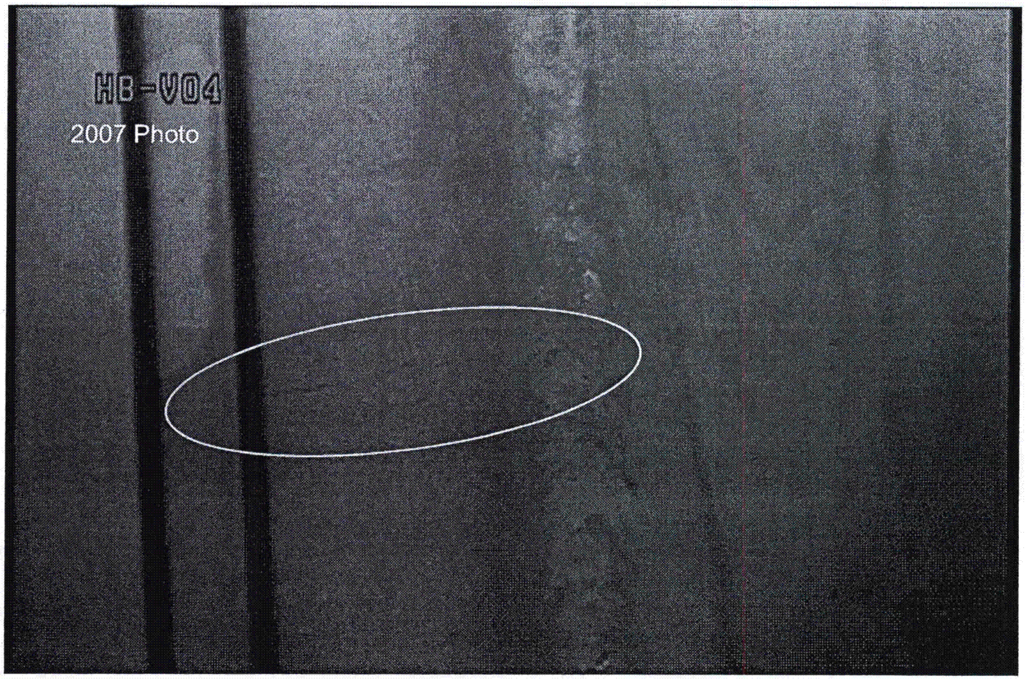


This 2007 photo shows the top of the vane bank (on the left) and the end panel (on the right) and the vertical weld in the center

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

Indication Notification Report

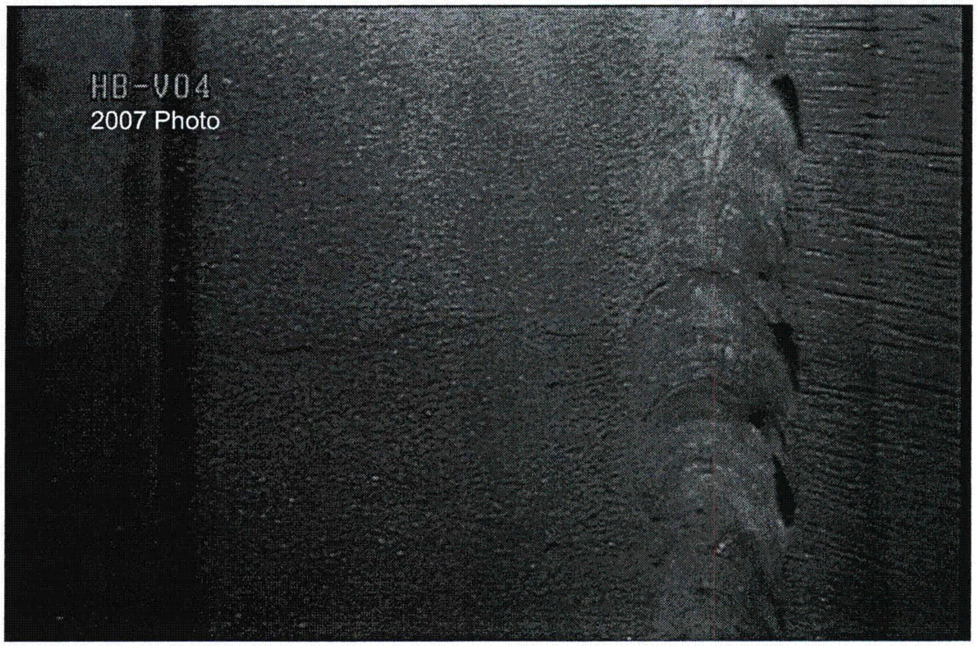




This 2007 photo is of the 1st indication from top down (Correlates to RFO25: 1st indication).

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

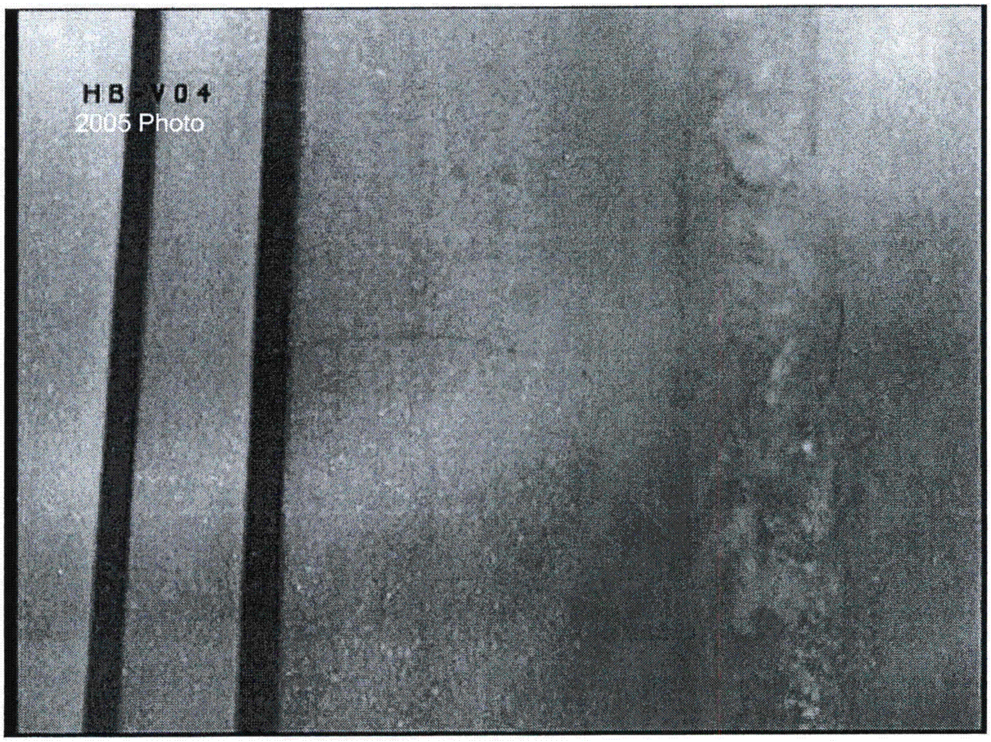
Indication Notification Report



This 2007photo is a close-up of the 1st indication (Correlates to RFO25: 1st indication).

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

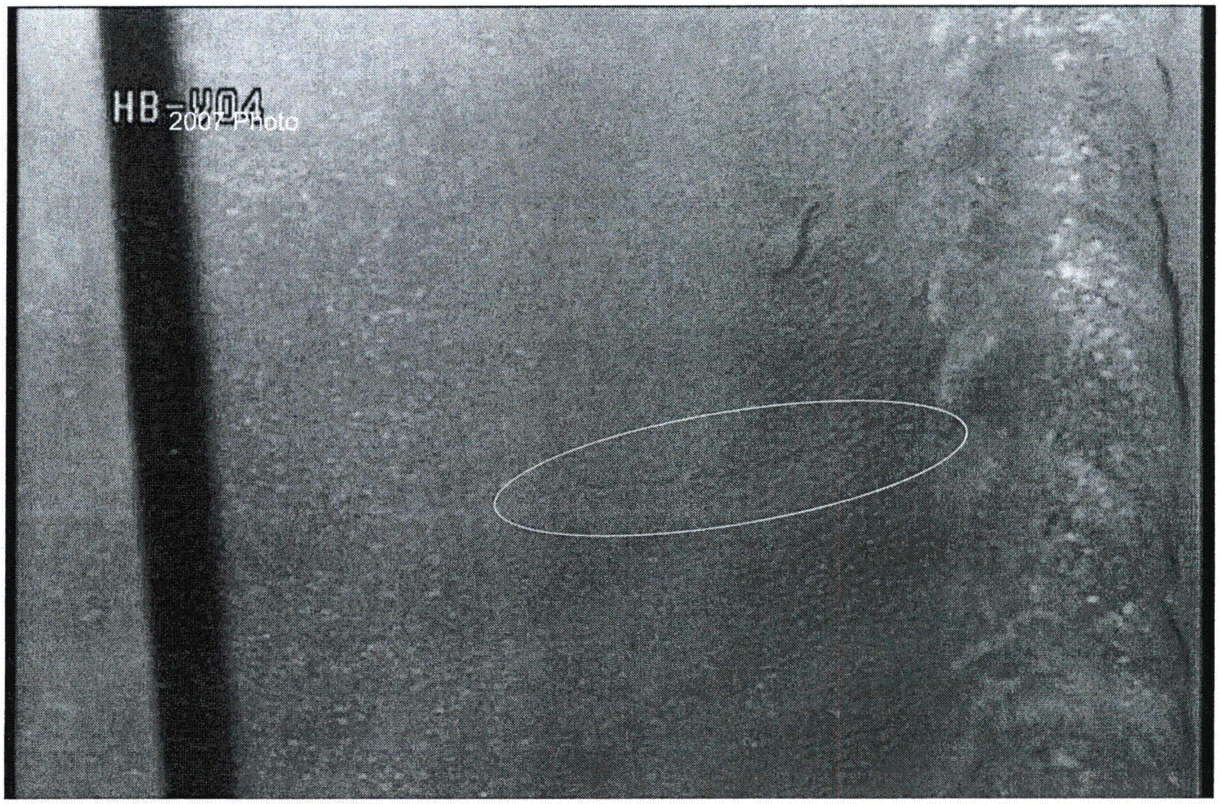
Indication Notification Report



This 2007 photo is the 2nd indication (Correlates to RFO25: 2nd indication).

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

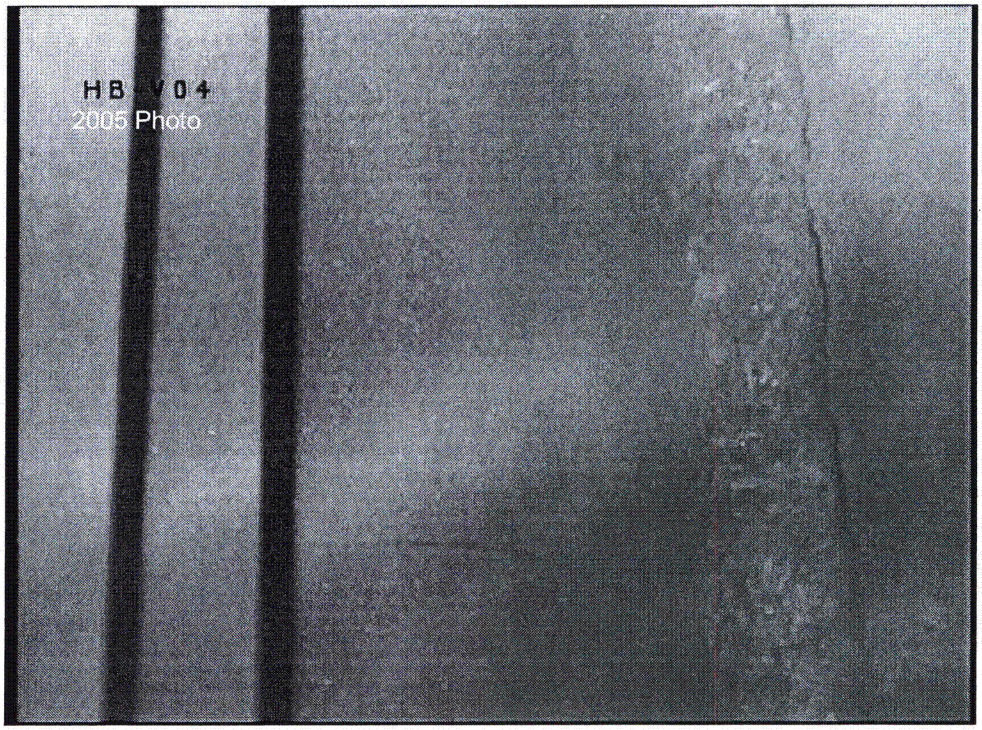
Indication Notification Report

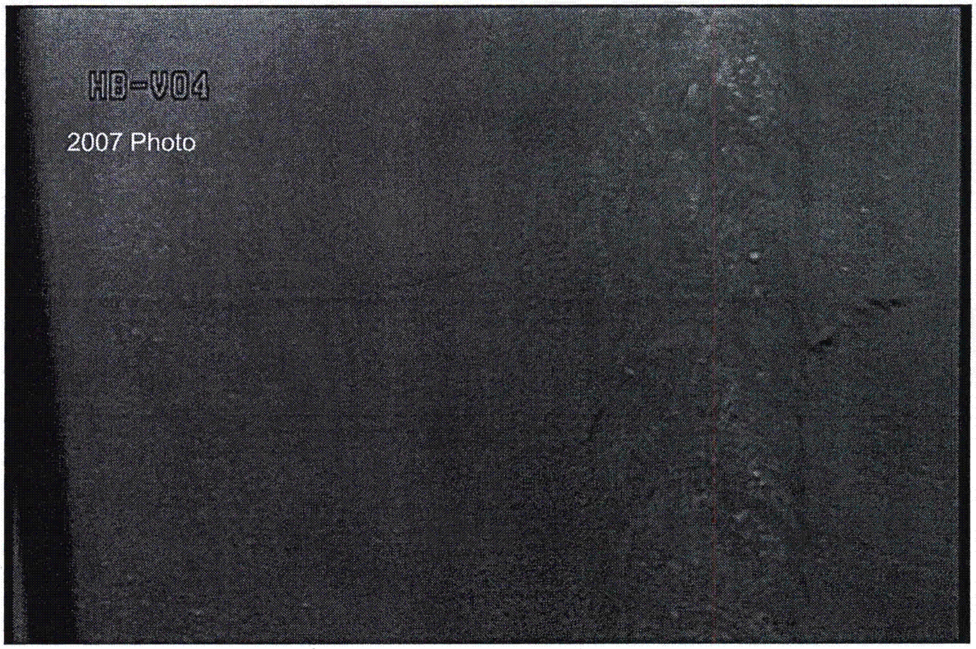


This is a 2007 photo of the 3rd indication and is a new RFO26 indication.

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

Indication Notification Report

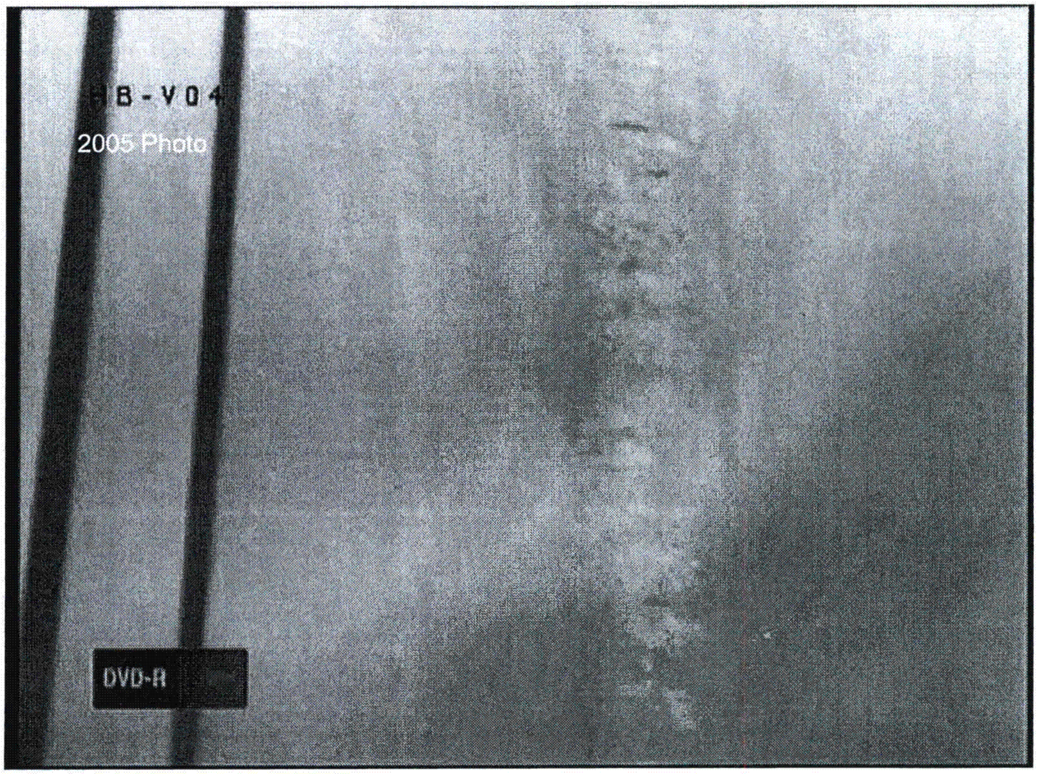




This is a 2007 photo of the 4th indication (Correlates to RFO25: 3rd indication)

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

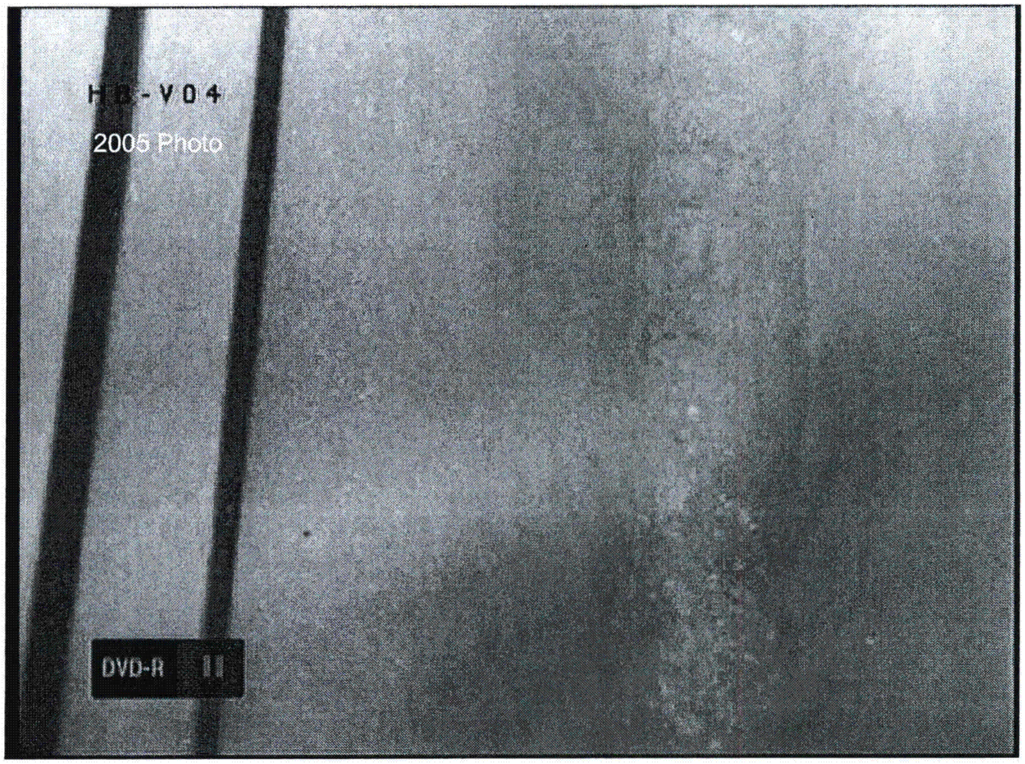
Indication Notification Report

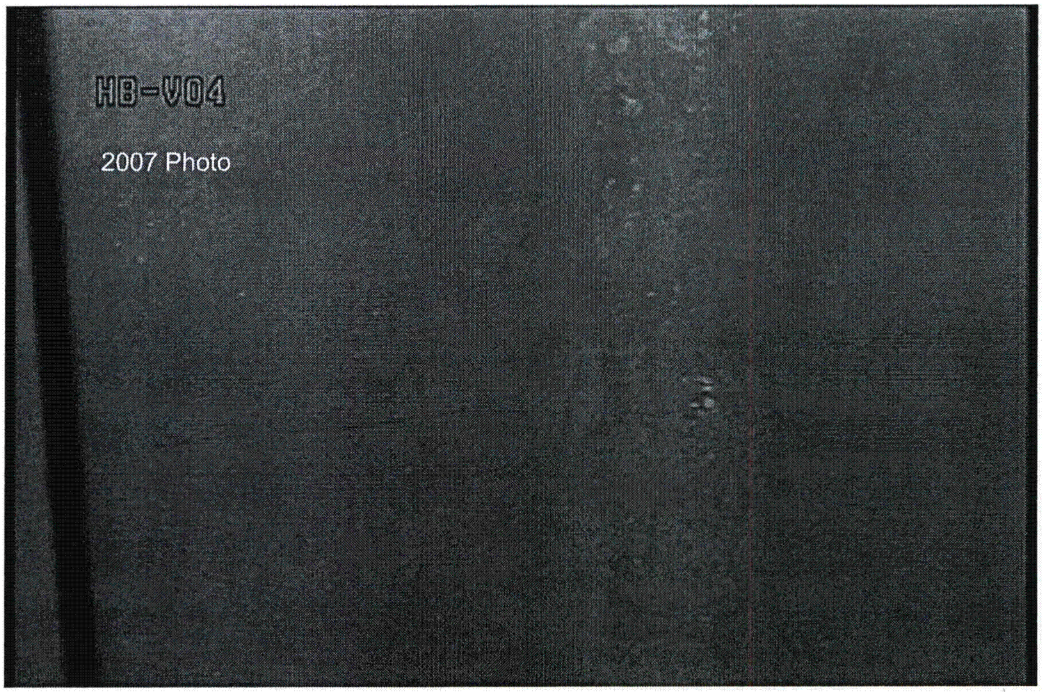


This is a 2007 photo of the 5th indication (Correlates to RFO25: 4th indication).

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

Indication Notification Report

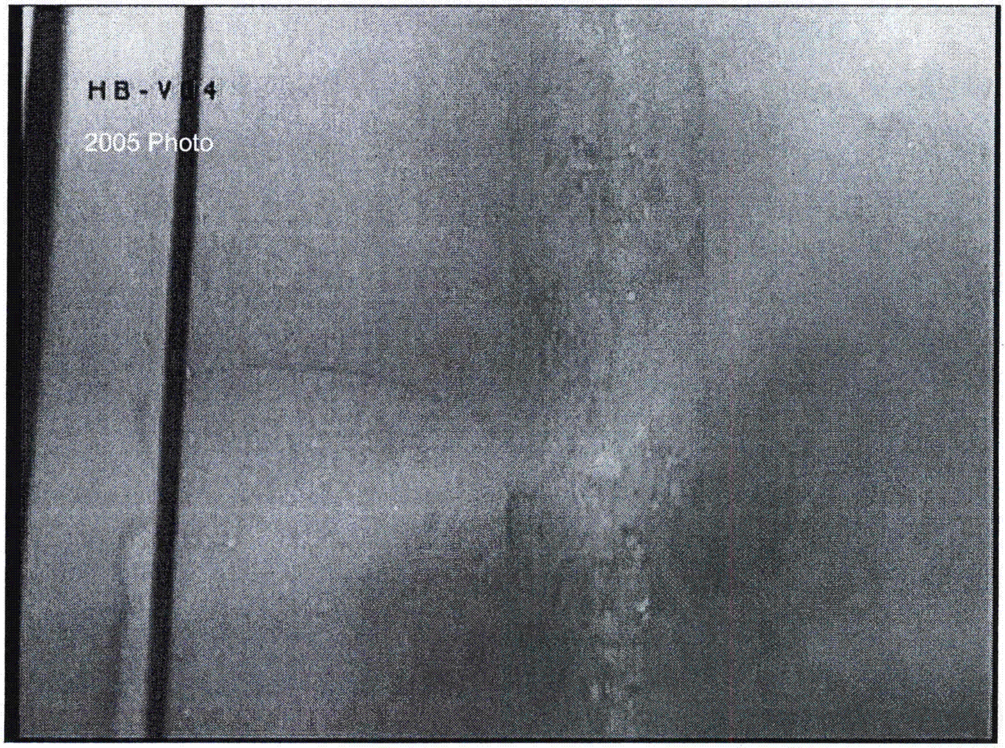


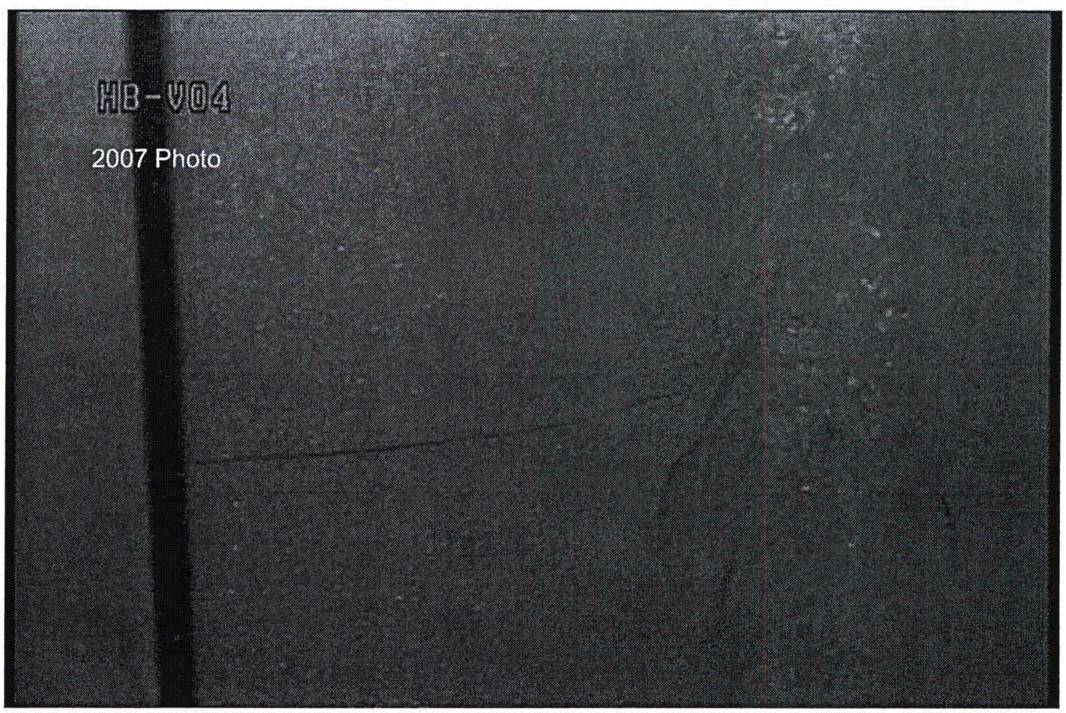


This is a 2007 photo of the 6th indication (Correlates to RFO25: 5th indication).

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

Indication Notification Report

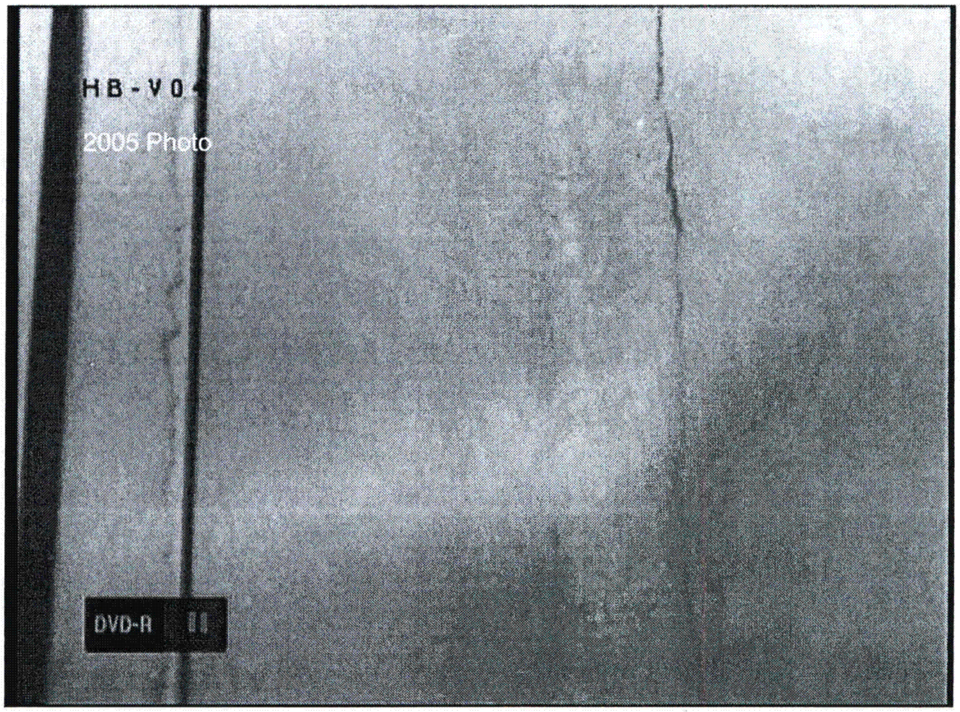


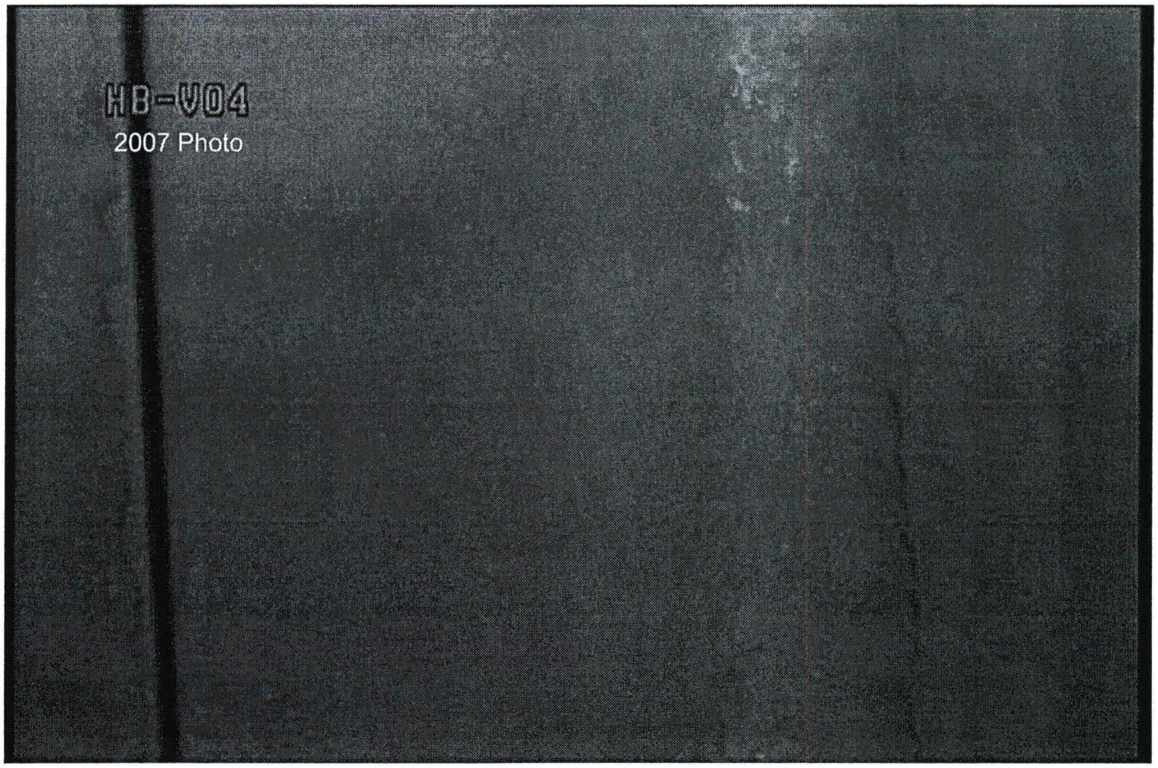


This is a 2007 photo of the 7th indication (Correlates to RFO25: 6th indication).

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

Indication Notification Report

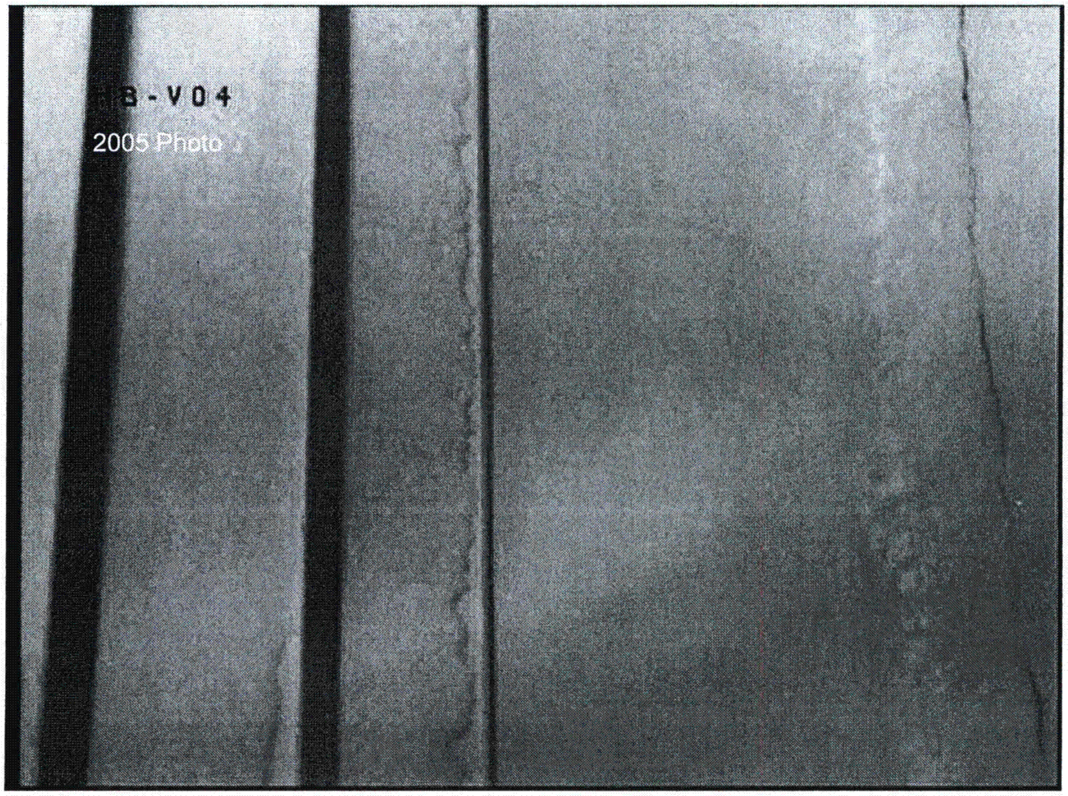




This is a 2007 photo of the 8th indication (Correlates to RFO25: 7th indication).

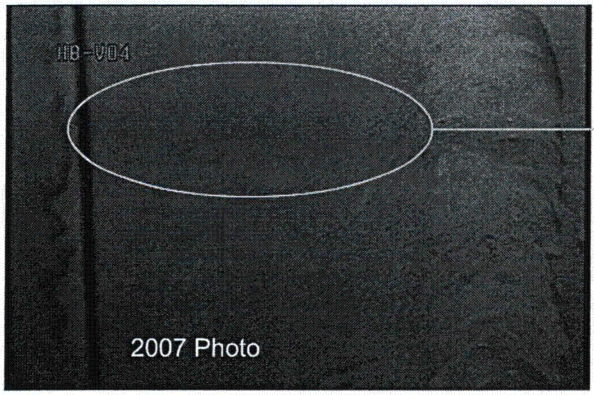
INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

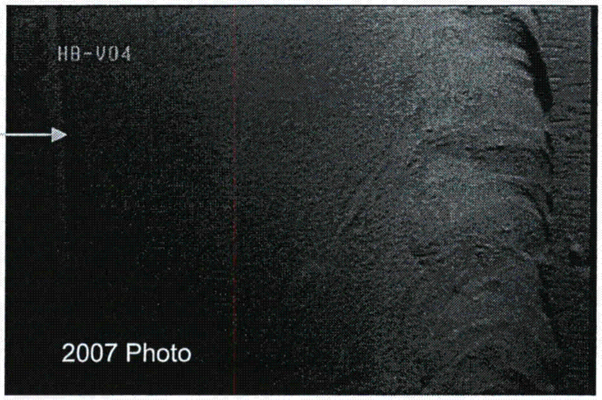
Indication Notification Report



RFO 25
8th
Indication

RFO 25
9th
Indication

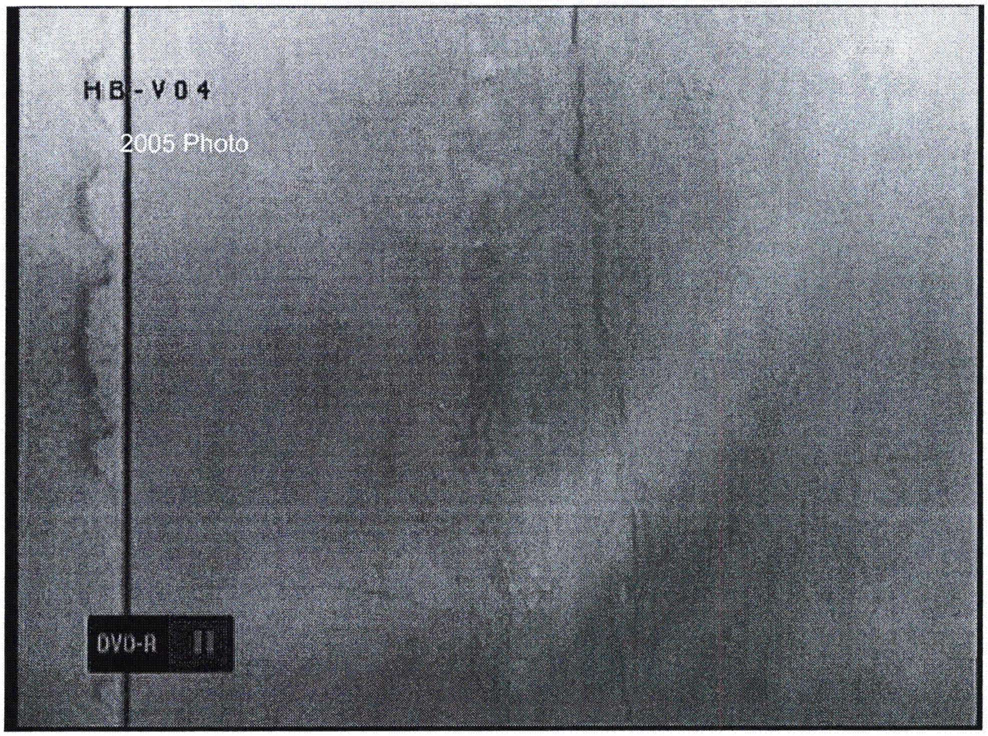


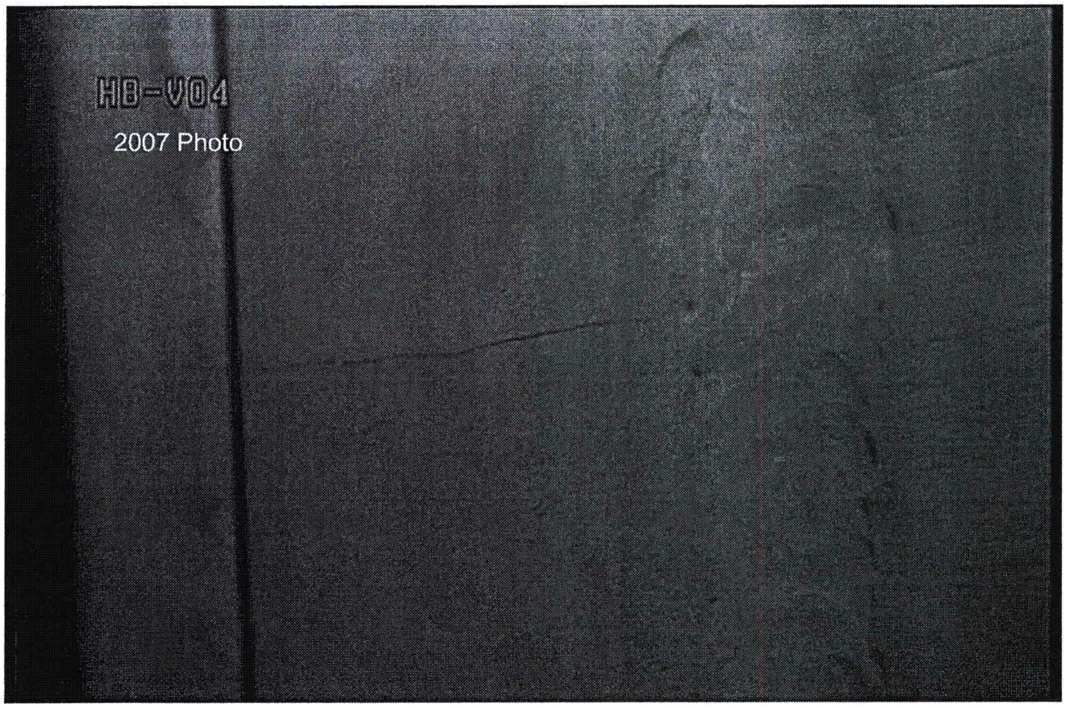


These 2007 photos show a linear indication and with a change of lighting there is no indication. This indication is considered non-relevant. (Correlates to RFO25: 9th indication).

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

Indication Notification Report

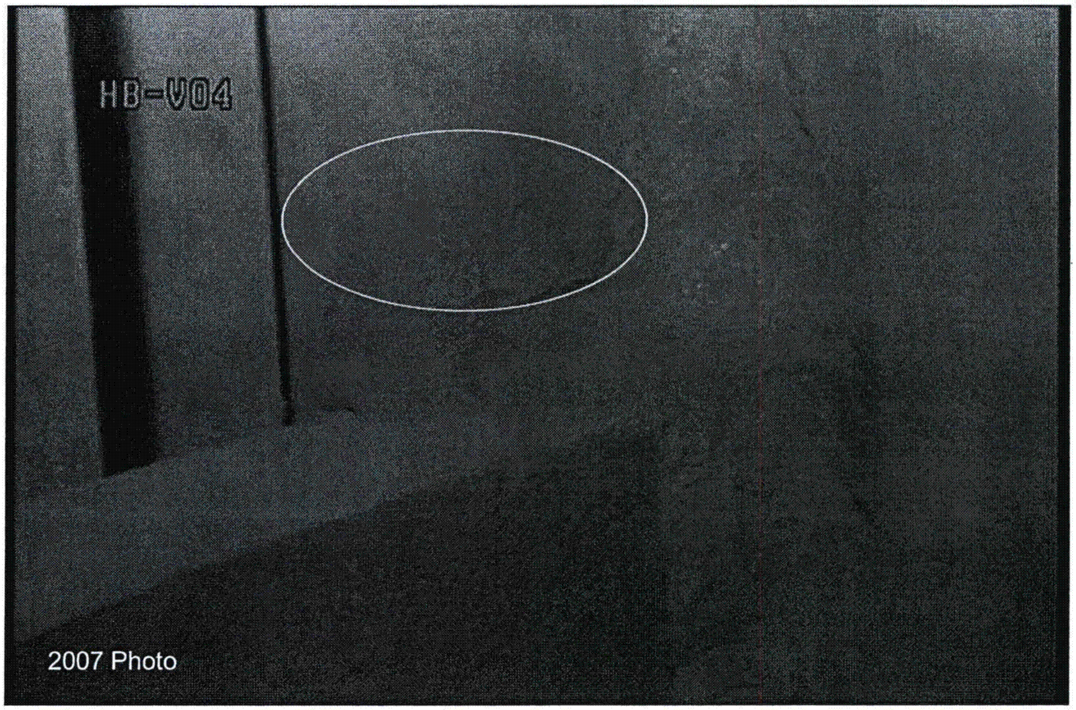




This is a 2007 photo of the 9th indication (Correlates to RFO25: 10th indication).

INR-IVVI-VYR26-07-10-Rev 1 Steam Dryer Interior HB-V04

Indication Notification Report



This is a 2007 photo of the bottom weld area and crud line.

NEC-JH_69

Life Prediction and Monitoring of Nuclear Power Plant Components for Service-Related Degradation

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Pacific Northwest National Laboratory,[1]
Richland, WA 99352

This paper describes industry programs to manage structural degradation and to justify continued operation of nuclear components when unexpected degradation has been encountered due to design materials and/or operational problems. Other issues have been related to operation of components beyond their original design life in cases where there is no evidence of fatigue crack initiation or other forms of structural degradation. Data from plant operating experience have been applied in combination with inservice inspections and degradation management programs to ensure that the degradation mechanisms do not adversely impact plant safety. Probabilistic fracture mechanics calculations are presented to demonstrate how component failure probabilities can be managed through augmented inservice inspection programs. [DOI: 10.1115/1.1344237]

Introduction

Evaluations of nuclear power plant safety have assumed that passive components such as pressure vessels and piping systems have very low failure probabilities, such that failures of these components make only negligible contributions to plant risk (e.g., core damage frequency). In the U.S. and other countries the design, fabrication, inspection, and maintenance of piping and vessels have followed the conservative engineering practices specified by the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Codes. The relatively small number of significant failures that have occurred during operating experience has demonstrated the soundness of the ASME code procedures. However, many plants will be approaching their design lives (e.g., 40 yr), with the expectation that continued operation beyond the original design period will need to be justified. Therefore, the assumption of continued high levels of structural reliability requires an extrapolation beyond the current base of operating experience that must be addressed as part of plant life extension efforts.

Whereas the replacement of active components (mechanical and electrical) is a routine part of plant maintenance, large-scale replacements of vessel and piping components is not economically feasible. The challenge is to make realistic life predictions, and to establish a high level of confidence in these predictions. A desired objective is to ensure that passive components continue to make only negligible contributions to plant risk relative to less easily managed contributions to risk such as failures of active components and operator errors.

Fatigue damage was originally identified as the life-limiting degradation mechanism for many pressure vessel and piping components during the design of nuclear power plants. With an aging population of operating plants, certain structural locations may exceed their original design lives based on calculated values of fatigue usage factors, although there has been no evidence of degradation as the predicted fatigue lives have been approached or exceeded. On the other hand, various degradation mechanisms, such as thermal fatigue, environmentally assisted fatigue, stress corrosion cracking, and flow-accelerated corrosion, were not anticipated during design, and have resulted in actual structural failures and early replacements and repairs to components.

This paper describes efforts in the nuclear industry to justify continued operation, with particular attention to components that have exhibited degradation or which may exceed original limits based on predicted design lives. Two technical bases for continued operation are presented. The first approach makes use of knowledge gained from plant operating experience to identify and manage degradation mechanisms. These mechanisms may not have been anticipated during the design of the plant, but given their actual occurrence have the potential to cause failures by small leaks, large leaks, or ruptures. The second approach addresses failure mechanisms, such as fatigue due to anticipated plant operating transients, which design calculations show the potential for occurrence, but for which plant operating experience has not yet shown any evidence of actual occurrence. Probabilistic fracture mechanics calculations demonstrate that an augmented level of inservice inspection can ensure acceptable failure probabilities for fatigue critical components.

Management Programs for Service-Related Degradation

Studies by Bush [1,2], Jamali [3], Thomas [4], and Wright et al. [5] have shown that piping failures are generally due to operational conditions, materials selection, and design features that were not adequately addressed or perhaps not addressed at all in the design of plant systems. On the other hand, those mechanisms such as mechanical fatigue due to anticipated operational transients, which have been considered as part of the plant design, have been addressed in a very effective manner and are seldom (if ever) the cause of service related failures.

Given the large number of potential service-related degradation mechanisms, the nuclear industry has adopted monitoring and managing practices, rather than life prediction and retirement practices, to ensure safe and reliable systems. The strategy involves the following steps:

- a reporting system to ensure that the industry can respond to adverse operating experience (detecting of cracking or leakage) before unanticipated degradation mechanisms impact a large number of plants and/or result in safety significant structural failures;
- augmented inservice inspections that are targeted to specific systems, materials, and/or operating conditions to ensure detection of early stages (small cracks or minimal wall thinning) of degradation mechanisms;

[1]Pacific Northwest National Laboratory is operated for the U.S. Department of Energy by Battelle Memorial Institute under Contract DE-AC06-76RLO 1830.

Contributed by the Pressure Vessels and Piping Division for publication in the JOURNAL OF PRESSURE VESSEL TECHNOLOGY. Manuscript received by the PVP Division, January 2000; revised manuscript received October 23, 2000. Editor: S. Y. Zamrik.

• changes to plant operating conditions (e.g., improved water chemistries) to decrease degradation rates to negligible levels;
• replacement of inadequate piping and vessel components with improved materials and/or design practices.

Some industry programs have been effective in responding to both anticipated and unanticipated degradation mechanisms. Ongoing efforts by the nuclear power industry to address service-related problems are described in the forthcoming.

ASME Section XI Inservice Inspection

Formal integrity management programs were first established for nuclear power plants in the early 1970s. Until that time, limited attention was given to the needs of inservice inspections (ISI) in early nuclear power plant designs. It was generally believed that system radioactivity would render periodic inspections impractical. Since the nuclear plant systems were being designed and constructed to higher quality standards than those applied to fossil plants, ISI was assumed to be unnecessary. However, by the late 1960s, the number of service induced defects requiring the repair of nuclear system components increased. This prompted a cooperative effort between the U.S. Atomic Energy Commission (AEC) and industry to develop inspection program standards under the oversight of the American National Standards Institute (ANSI) and the American Society of Mechanical Engineers (ASME). By 1970, the ASME Boiler and Pressure Vessel Code, Section XI "Inservice Inspection of Nuclear Reactor Coolant Systems" was published.

Over 50 percent of the inspection categories pertained to welds. The inspection locations were primarily selected based on factors such as: component design stresses, estimated fatigue usage, dissimilar metal welds, and irradiation effects.

Originally, service-induced flaws were assumed to occur from random causes, at random locations, and at random times. Therefore, the Section XI inspection program relied upon a representative sampling of weld locations and randomized the timing of inspections as much as possible. The examination procedures and flaw acceptance standards assumed that the principle cause of failure would be due to fatigue stress cycles created by anticipated design cyclic loads (i.e., thermal fatigue). For Class 3 systems (i.e., service water systems) Section XI program requirements are limited to periodic leak and hydrostatic pressure testing—no volumetric or surface examinations are required.

Service Experience Insights

Service experience [6,7] has shown no correlation between actual failure probability and design stresses in the Design Report. Failures (cracks, leaks, and breaks) typically result from degradation mechanisms and loading conditions (i.e., IGSCC, flow accelerated corrosion, thermal stratification, etc.) not anticipated in the original design. Depending on the degradation mechanism present, failures are not necessarily limited to weld locations.

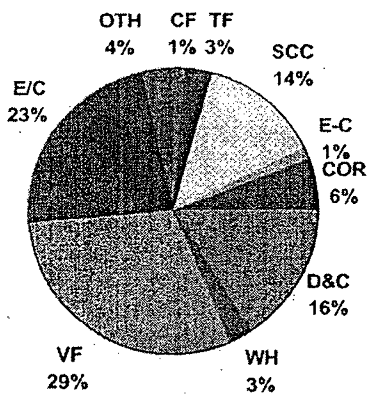

Fig. 1 Piping failure events in U.S. nuclear plants (1961–1996)

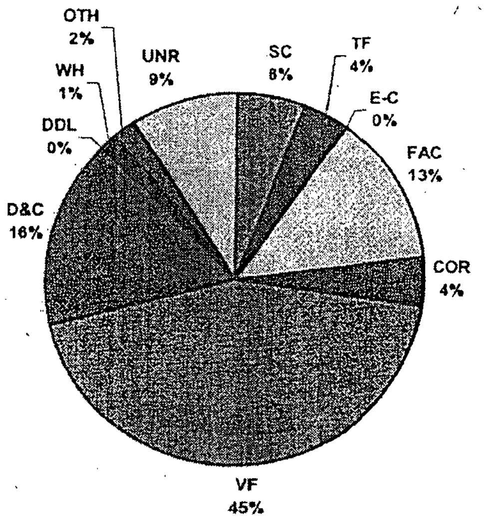

Fig. 2 Service failures in small-bore piping (<2 in. NPS)

The Swedish Nuclear Power Inspectorate (SKI) compiled a database on reported piping failure events (leaks, breaks, and ruptures) in U.S. commercial nuclear power plants [8]. This database includes a total of 1511 piping and piping component failures on various safety and balance-of-plant (BOP) systems that have been reported to U.S. regulatory bodies from December 1961 through October 1995, encompassing 2068 reactor operating years. Figure 1 shows the distribution of all piping failures according to the following causes:

• corrosion fatigue—CF
• thermal fatigue—TF
• stress corrosion cracking—SCC
• corrosion attack—COR
• erosion and cavitation—E-C
• flow-accelerated corrosion (i.e., erosion corrosion)—E/C
• high-cycle vibration fatigue—VF
• water hammer—WH

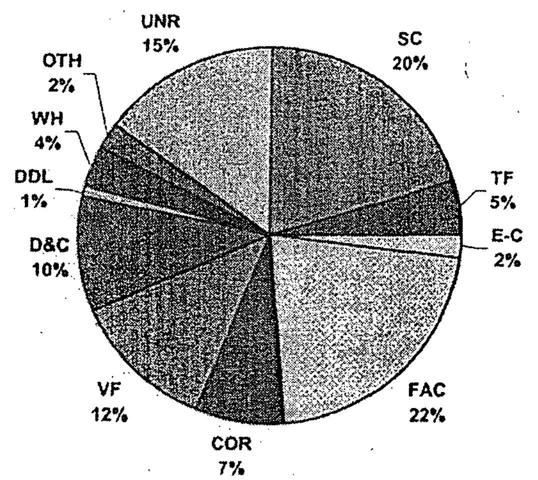

Fig. 3 Service failures in large-bore piping (>2 in. NPS)

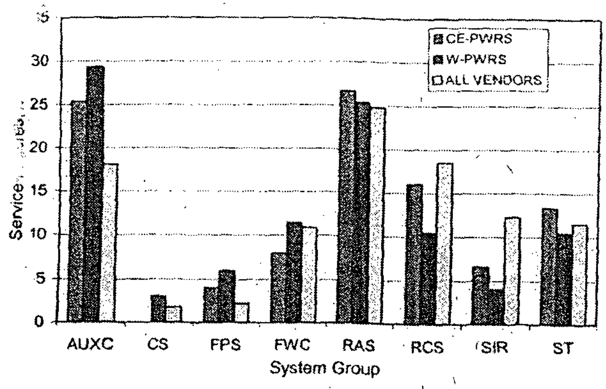

Fig. 4 Service failures by system groups

- design and construction errors—D&C
- other—OTH

The data of Fig. 1 shows that only 3 percent of all the reported service-induced piping failures were caused by thermal fatigue. This suggests that in their present form the ASME Section XI ISI program requirements are relatively ineffectual with regard to reducing overall piping failure probabilities. Approximately 72 percent of all reported failures were due to degradation mechanisms not addressed by ASME Section XI. For approximately 25 percent of all the reported events, piping failure resulted from failure mechanisms that were not associated with a particular damage mechanism. These include pipe failures caused by transient loading conditions and other factors such as construction errors, water hammer, overpressure, and frozen pipes. In these cases traditional inspection programs may be ineffective in preventing or reducing the piping failure probability.

Table 1 Service failure data system grouping

GROUP DESIGNATOR	SYSTEM GROUP DESCRIPTION	REPRESENTATIVE SYSTEM NAMES
RCS	Reactor Coolant System	Pressurizer, Reactor Coolant System
SIR	Safety Injection and Recirculation System	High and Low Pressure Safety Injection, Residual Heat Removal, Shut Down Cooling, Accumulator or other passive injection systems
CS	Containment Spray System	Containment Spray System
RAS	Reactor Auxiliary Systems	Component Cooling Water, Chemical Volume and Control, Spent Fuel Pool Cooling, Radwaste (no salt or dirty water systems)
AUXC	Auxiliary Cooling Systems	Service Water; Salt Water Cooling, Main Circulating Water, and other dirty water systems
FWC	Feedwater and Condensate Systems	Main Feedwater System, Auxiliary Feedwater System, Condensate System
ST	Main and Auxiliary Steam Systems	Main and Auxiliary Steam Systems
	Fire Protection Systems	Fire Protection System

Figures 2 and 3 compare service failures in small bore (<2 in. NPS) and larger bore (>2 in. NPS) piping. Approximately three-quarters of the reported service failures in small-bore piping were caused by either high-cycle vibration fatigue (VF), flow-accelerated corrosion (FAC), or design and construction errors (D&C). Almost half (45 percent) of the small-bore pipe failures were due to vibration fatigue. The majority of these failures occurred at socket-welded connections in poorly supported or cantilevered vent and drain lines <1 in. NPS.

Over 50 percent of the reported large bore piping service failures were caused by stress corrosion cracking (SCC), VF, and FAC. SCC and FAC accounted for 42 percent, and VF accounted for 12 percent of the reported failures. Sixteen percent of the small-bore failures were caused by D&C compared to 10 percent for large-bore piping. This appears to reflect field welding and fabrication difficulties associated with smaller-diameter piping.

Figure 4 shows the number of service failures reported in several plant system groups. Each system group is described in Table 1. System group service experience for Combustion Engineering PWRs, for Westinghouse PWRs, and for ALL plants is shown. Over half of the reported service failures in Combustion Engineering and Westinghouse PWRs occurred in reactor auxiliary systems (component cooling water, chemical volume and control, spent fuel pool cooling, radwaste, etc.) and auxiliary cooling systems (service water, salt water cooling, main circulating water, etc.).

Augmented Inspection Programs

For some of the more significant causes of piping failures, augmented inspection programs have been implemented. These programs, many of which have been mandated by the NRC, are designed to address component integrity relative to the impacts associated with a specific damage mechanism.

Intergranular Stress Corrosion Cracking. Stress-corrosion cracking (SCC) refers to cracking caused by the simultaneous presence of tensile stress and a corrosive medium. The important variables affecting SCC are temperature, water chemistry, metal composition, stress, and metal microstructure. Both intergranular (cracking proceeds along the material grain boundary) and transgranular (crack growth is not affected by the presence of grain boundaries) cracking have been observed. Intergranular stress corrosion cracking (IGSCC) results from a combination of sensitized materials (caused by a depletion of chromium in regions adjacent to the grain boundaries in weld heat-effected zones), high stress (residual welding stresses), and a corrosive environment (high level of oxygen or other contaminants).

IGSCC is encountered most frequently in austenitic stainless steels that become sensitized through the welding process and are subjected to BWR operating environments. The susceptible areas extend into the base material a few millimeters beyond either side of the weld—the weld "heat-affected zone." Welds in materials considered to be resistant to sensitization from welding are not susceptible to degradation from IGSCC.

A discussion of the IGSCC problems in BWR nuclear plants and the associated augmented program requirements can be found in Generic Letter 88-01 [9] and in NUREG 0313 [10]. The industry was required to establish programs that included the following:

- implement piping replacements or other measures to mitigate IGSCC;
- augment the existing Section XI ISI program to incorporate an inspection scope and frequency consistent with the extent of mitigation actions implemented;
- improve leak detection and monitoring programs;
- implement programs to improve NDE inspector performance in the detection and characterization of IGSCC damage.

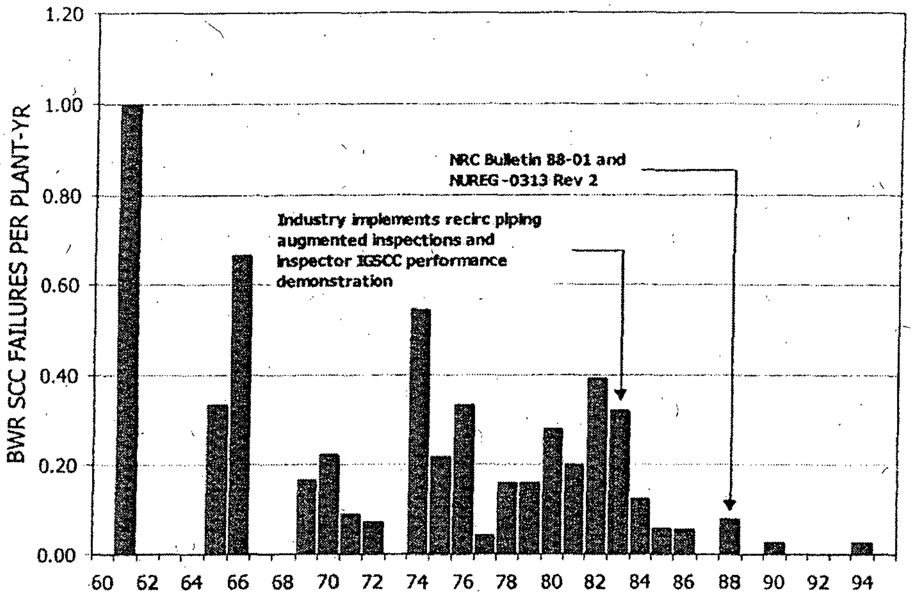

Fig. 5 BWR SCC failures per plant year

Figure 5 shows that since the implementation of these program requirements, the frequency of IGSCC caused piping failures, which might otherwise have increased, has instead been significantly reduced.

Flow-Accelerated Corrosion. Flow-accelerated corrosion (FAC) is a complex phenomenon that exhibits attributes of erosion and corrosion in combination. Factors that influence whether FAC is an issue are velocity, dissolved oxygen, pH, moisture content of steam, and material chromium content. Carbon steel piping with chromium content greater than 1 percent and austenitic steel piping is not susceptible to degradation from FAC.

At the end of 1996, industry initiated efforts to develop a program to address erosion-corrosion. These initial efforts were directed at single-phase systems. Initial inspections were completed on all single-phase systems by 1989. Erosion-corrosion programs were in place on both single and two-phase by 1990 [11]. Since that time, service experience (Fig. 6) suggests that the number of failures due to erosion-corrosion has been reduced.

EPRI report NSAC/202L [12] provides general guidelines for the identification and inspection of components subject to FAC degradation.

Corrosion Attack in Service Water Systems. Uniform corrosion attack in service water piping, microbiologically induced corrosion (MIC), crevice corrosion, and pitting were typical causes of failure events of pipe components grouped in this category. Of these, MIC is the predominant corrosion mechanism in

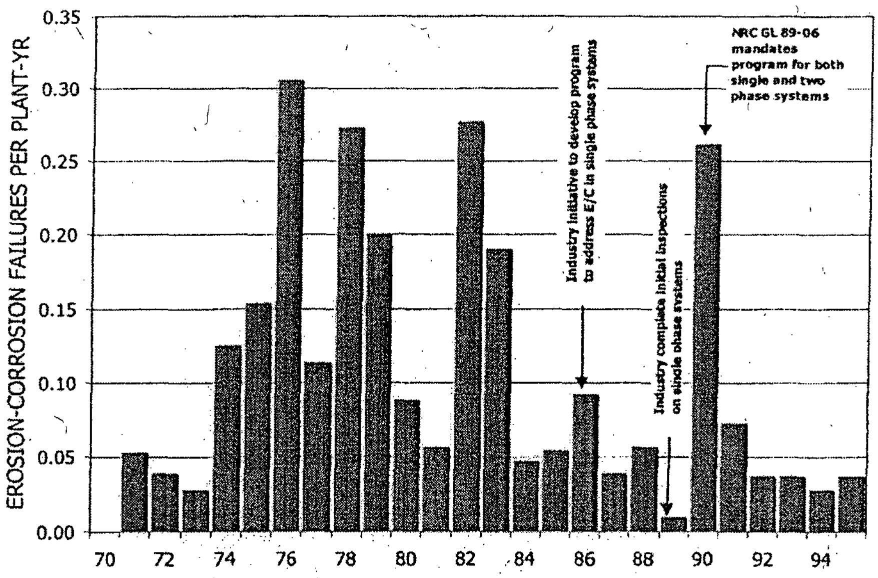

Fig. 6 Erosion-corrosion failures per plant year

these systems. In MIC, microbes, primarily bacteria, cause widespread damage to low-alloy and carbon steels. Similar damage has also been found at welds and heat-affected zones for austenitic stainless steels. Piping components with fluids containing organic material or with organic material deposits are most susceptible to .. The most vulnerable components are raw water systems, storage tanks, and transport systems. Systems with low to intermittent flow conditions, temperatures between 20–120°F and pH below 10, are primary candidates.

In response to NRC Generic Letter 89-13, industry was instructed to implement a comprehensive program to address corrosion in service water systems. Prior to this, the service water integrity programs relied on the Section XI periodic leak and hydrostatic pressure test requirements. Under the Section XI program, the service water system integrity management approach was "reactive" in nature; that is, corrective action was taken when damage was sufficient to result in visible leakage. The Generic Letter 89-13 augmented programs require plants to take a more "proactive" approach to the problem. For example, many programs implemented improved chemistry control to mitigate the establishment of MIC sites, volumetric inspections (UT/RT examinations), and component condition monitoring and trending.

EPRI reports TR-103403 [13], NP-5580 [14], and NP-6815 [15] provide additional information regarding MIC degradation.

High-Cycle Mechanical Vibration Fatigue. More and more attention has recently been paid by operating plants to prevent unexpected piping failures due to high-cycle vibration fatigue. Small-bore pipe (<1 in. NPS) socket-welded vent and drain connections in the immediate proximity of vibration sources tend to be most susceptible to this failure mechanism [16–18]. Unlike the previously discussed mechanisms, vibration fatigue does not lend itself to periodic inservice examinations (i.e., volumetric, surface, etc.) as a means of managing this degradation mechanism. The nature of this mechanism is such that, generally, almost the entire fatigue life of the component is expended during the initiation e. Once a crack initiates, failure quickly follows. Therefore, absence of any detectable crack may not assure reliable component performance. In addition, for many of these components, the plant conditions when vibration levels are unacceptable may be very difficult to predict and limited to short time periods of unique plant/system configurations. This would explain why we continue to observe cases where vibration fatigue failures occur late in the plant's operating life [8]. Therefore, the fact that a vibration failure has not occurred within the first few years of plant operation may not preclude future failures.

Figure 7 shows the number of pipe failure events per reactor plant-year reported to NRC as being caused by high-cycle vibration fatigue. Prior to 1976 piping vibration fatigue was addressed

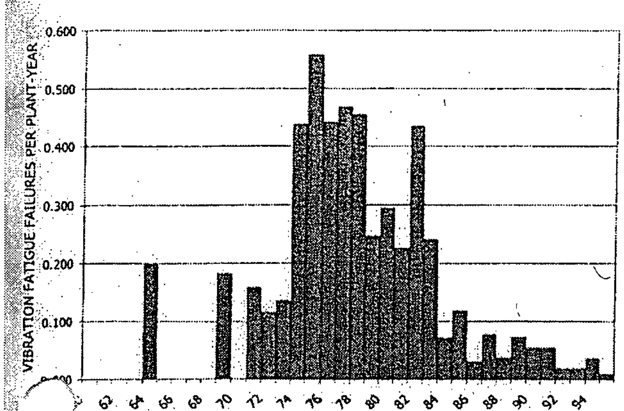

Fig. 7 Vibration fatigue failures per plant year

as a result of a problem resolution. Between 1976 and 1982, the significant amount of vibration fatigue related failures (Fig. 7) fostered increased attention to this problem by code and regulatory bodies. The NRC incorporated requirements to perform vibration testing as part of nuclear power plant initial testing programs [16], and by 1982 the ASME published an operating and maintenance standard [19] which specified requirements for pre-operational and initial start-up vibration testing in nuclear power plants.

Risk-Based Inservice Inspection. Service experience and the augmented inspection programs have demonstrated a need on Section XI's part to move in new directions and shift its emphasis away from simple inservice "inspection" rules to establishing effective integrity management programs for nuclear plants. Ideally, these new programs should include the following characteristics:

1 Future programs need to be based on an understanding of failure mechanisms and focus attention on the locations in the plant system most likely to be affected by these mechanisms. This will allow plants to identify problems in a proactive manner, so that corrective actions can be planned and implemented before failures occur.

2 Monitoring and inspection methods need to be designed specifically for the degradation mechanism of concern. This has been referred to as "inspection-for-cause."

3 The integrity management program should be designed to ensure reliable component operation. For example, inspection frequencies may need to be adjusted to ensure that the failure probability of the component is maintained at an acceptable level. ASME Section XI hopes to accomplish these objectives moving in the direction of risk-informed inservice inspection (RIISI).

As a first step, ASME Section XI has recently developed pilot code cases that allow for the use of alternative RIISI rules for piping. These code cases grew out of work sponsored by ASME research [20] and EPRI [21]. The three code cases implementing this technology have been incorporated into ASME Section XI Code Cases N-560, N-577, and N-578. These initial efforts focused primarily on the identification of inspection locations and the implementation of appropriate inspection methods. Industry pilot applications [22,23] have been completed for each code case. Each application has been reviewed and approved by the NRC for consistency with NRC guidelines [24].

Probabilistic-Based Inspection Strategies

Thus far success of the initial RIISI studies has been measured in terms of estimated reductions in nuclear power industry and regulatory burden, anticipated man-rem exposure reductions and calculated improvements in reactor safety. These improvements in safety have assumed that the selected inspection locations are examined using reliable NDE methods at appropriate frequencies in order to achieve a reduction in failure probabilities. In the long run, ultimate success will be seen in a reduction in the occurrence of piping leaks in these systems. Therefore, future inspection strategies will need to manage component failure frequencies.

In this section we show how a probabilistic approach can be applied to determine inspection frequencies that account for demonstrated NDE performance and ensure reliable piping performance is maintained throughout the component's original or extended operating life. In the example described in the forthcoming, we assume that the weld location is subject to thermal fatigue. The inspection frequency necessary to maintain the component's failure probability at or below that associated with the fatigue limit specified in the original construction ASME Section III design code (e.g., cumulative usage factor (CUF) must be less than unity) is then determined.

Probabilistic Approach. Probabilistic fracture mechanics calculations are presented to demonstrate that an augmented level

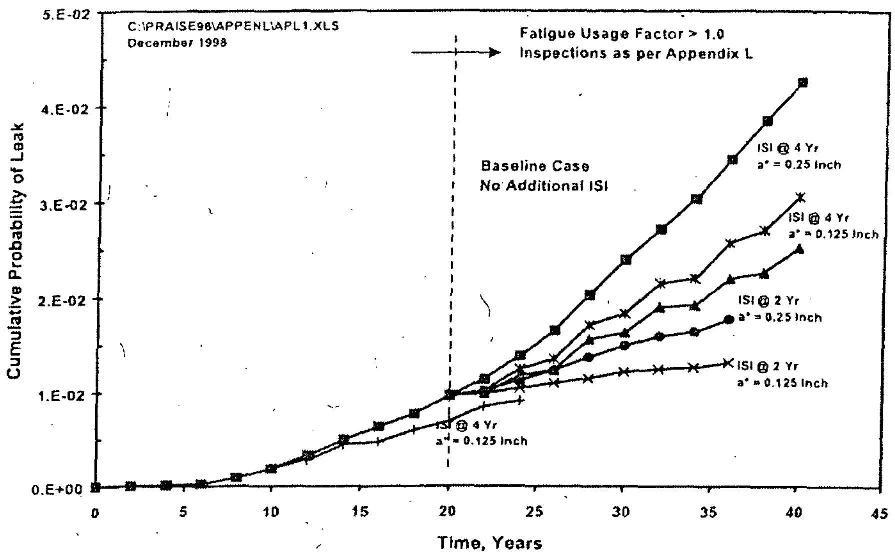

Fig. 8 Calculated probability of leak before and after implementation of inspection program

of inservice inspection can ensure that failure rates of fatigue critical components should not increase as operation is continued beyond usage factors permitted by the design code. Uncertainties in flaw growth rates and in flaw detection were addressed by application of the probabilistic fracture mechanics code pc-PRAISE [25]. Suitable inspection frequencies were established for a given flaw detection capability (probability of detection or POD curve) by adopting a goal for an acceptable piping failure probability (i.e., probability of through-wall crack per weld per year). Continued operation for calculated CUFs exceeding unity was taken to be acceptable only if additional inspections are performed. These inspections are required to maintain calculated failure rates at levels less than (or equal to) calculated failure rates before the usage factors became unity.

Probabilistic Calculations. The example considers a stainless steel pipe (29-in. outside diameter by 2.5-in. wall) which is loaded at 5000 cycles per year to give a CUF=1.0 after 20 yr of operation given a weld root stress concentration factor of 3.0. This corresponds to a nominal alternating stress of 27.3 ksi and a peak alternating stress, at the weld root, of 81.9 ksi.

The pc-PRAISE model assumed semi-elliptical surface flaws with aspect ratios of 12 and 20, and a Paris law for fatigue crack growth having a mean rate corresponding to constants of $C = 9.14\text{E-}12$ and $m = 4$. A simplified treatment of flaw initiation was assumed. At time=0.0, very small inner surface cracks were assumed to be present, with depths uniformly distributed between 0.005–0.010 in.

The alternative inspection frequencies were limited to the case of no inspections and inspections every 2 or 4 yr, with the inspection program being introduced after 20 yr of operation. The reliability for the ultrasonic NDE was described by the error function-type curves used by the pc-PRAISE code to describe flaw detection. Two bounding curves were assumed for purposes of the demonstration calculations. The less effective NDE assumed a threshold detection capability (50 percent POD) for a 0.10-t flaw ($a^* = 0.25$ in.), whereas the more effective NDE had a 50-percent POD for a 0.05-t flaw (0.125-in.). In each case, the POD curve provided significantly better detection capabilities for flaws of greater depths, such that flaw depths 0.25 and 0.50 in., respectively, or about twice the threshold size, could be detected with a probability of better than 90 percent.

Figure 8 shows the predicted cumulative probability of leak (through-wall crack) as a function of the operating time (0 to 40 yr). At 20 yr (when the calculated CUF becomes 1.0), the cumulative leak probability is about 1.0E-02, or one chance in 100 that the weld would fail. If no inspections are performed, the cumulative failure probability curve continues to rise and with an increasing failure rate. All of the alternative inspection scenarios (combinations of POD and inspection frequency) reduce the calculated failure probabilities, but some scenarios reduce the failure probability much more than others. The most effective inspection ($a^* = 0.125$ in.) reduces the failure rate by about an order of magnitude compared to the alternative of no inspection. In this case the failure rates during the second 20 yr of operation are actually substantially lower than the corresponding rates during the first 20 yr of operation. Some of the other less rigorous inspections of Fig. 8 are also sufficiently effective to maintain the calculated failure rates at or below the rate that exists at the time (20 yr) when the CUF attains the limiting value of unity. For example, an Appendix L inspection with a 4-yr frequency and $a^* = 0.125$ in. would meet the probabilistic criteria as well as the alternative of a 2-yr frequency with $a^* = 0.25$ in. Therefore, in this extreme case where thermal fatigue loading is significantly high, a 2–4-yr inspection frequency will maintain the component's reliability at design basis levels.

Conclusions

The nuclear power industry has successfully implemented programs to manage degradation of pressure boundary components. These programs have focused on unexpected degradation mechanisms that have impacted plant operations well before the end of the expected plant design life. Programs have also been implemented to address potential mechanisms such as fatigue cracking that were identified as life limiting as part of the plant design basis. Monitoring of components in accordance with plant inservice inspections programs can ensure that the reliability of piping systems is maintained throughout the remaining design life, and address issues related to plant life extension beyond the original 40 yr of the original design.

Inspections at appropriate frequencies with reliable NDE methods can manage the potential degradation mechanisms, and thereby justify continued operation even when calculated design limits may be exceeded. It is even possible with an aggressive inspection program to decrease failure frequencies during the later periods of plant life to the same levels that existed relatively early in life.

By applying probabilistic methods, future inspection strategies cannot only be consistent with the service conditions and the demonstrated performance levels of the NDE methods, but will ensure that the reliability of the piping is maintained over periods of continued operation. Inspection strategies, designed in this fashion, will be a powerful addition to current risk-based ISI models.

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TVA 64 (OS-9-65)

UNITED STATES GOVERNMENT

NEC-JH_70

Memorandum

TENNESSEE VALLEY AUTHORITY

B25 '87 0127 028

TO : H. L. Abercrombie, Site Director, ONP, O&PS-4, Sequoyah Nuclear Plant

FROM : D. W. Wilson, Project Engineer, Sequoyah Engineering Project, DNE, DSC-E, Sequoyah Nuclear Plant

DATE : JAN 27 1987

SUBJECT: SEQUOYAH NUCLEAR PLANT UNITS 1 AND 2 - PRELIMINARY REPORT ON THE CONDENSATE-FEEDWATER PIPING INSPECTION - SUSPECTED EROSION-CORROSION AREAS

Attached for your review is the preliminary report of SQN condensate-feedwater inspection. The results indicate that there is no wall thinning due to erosion-corrosion. However, there may be [redacted] The remaining wall in that area has not been reduced below the minimum design wall thickness. Appropriate surveillance instructions shall be written to monitor the suspect areas. The instruction will be written by Operations Engineering Services' metallurgical employees and is expected to be in place by June 30, 1987.

The final report will include the results of ultrasonic examinations of the elbows downstream of A and B pump and will be issued the week of February 6, 1987.

D. W. Wilson

CRB:DFG:RLP
Attachment
cc (Attachment):
RIMS, SL 26 C-K
M. J. Burzynski, ONP, O&PS-4, Sequoyah
J. C. Key, DNE, DSC-E, Sequoyah
J. H. Sullivan, ONP, SB-2, Sequoyah
B. M. Patterson, ONP, POB-2, Sequoyah (Attn: E. L. Booker)

Principally Prepared By: Robert L. Phillips and Terry R. Woods, extension 6946

HC7017.01

SEQUOYAH NUCLEAR PLANT UNITS 1 AND 2 - PRELIMINARY REPORT ON CONDENSATE-FEEDWATER PIPING INSPECTION - SUSPECTED EROSION-CORROSION AREAS

References:
1. D. W. Wilson's memorandum to H. L. Abercrombie dated December 19, 1986, "Sequoyah Nuclear Plant Units 1 and 2 - Inspection of Feedwater Piping for Wall Loss" (B25 861219 001)
2. Report by P. Berge and F. Khan, of Electricite de France, dated May 1982, "Corrosion Erosion of Steels In High Temperature Water and Wet Steam"
3. EPRI NP 3944 report, "Erosion/Corrosion in Nuclear Plant Steam Piping; Causes and Inspection Program Guidelines"

Background

On December 9, 1986, Surry Station Nuclear Plant had a pipe rupture on the condensate-feedwater system that caused several fatalities. The rupture was caused by localized wall thinning at a pipe-to-elbow weld. The thinning mechanism was identified as erosion-corrosion (EC). Sequoyah Nuclear Plant (SQN) implemented a program to identify possible EC damage (see reference 1). The program was developed from technical information from Surry Station, INPO network, regional and resident NRC inspectors, and information from references 2 and 3. EC is characterized by dissolution of protective magnetite film by a high temperature liquid stream in contact with steel surfaces. EC damage is normally found in elbows on the extrados (outer radius); however, it may also be seen on the intrados (inner radius). The phenomenon is usually observed in plain carbon and low alloyed steels at elevated temperatures. The following are factors influencing the EC mechanisms.

- pH and water and/or steam chemistry (O_2 concentration)?
- Material composition
- Flow path geometry
- Velocity
- Temperature

Incorporating the above factors and experience from Surry Station, a temperature boundary of 300 to 400 degrees Fahrenheit was established for initial inspection. These areas were considered to have the highest probability of damage. The locations inspected are identified in figures 1, 2, and 3.

[redacted] The plants also had similar operating parameters at the time of failure (i.e., water chemistry). The piping that failed had

The UT data was uniform and consistent and indicated that there was no thinning occurring as a result of EC, which would appear to be localized areas of non-uniform thinning. With one exception, there were no readings below the minimum thickness established in accordance with ANSI specifications. Wall thickness measurements taken on the discharge side of the feedwater pump on a 24- by 16-inch reducing elbow (Grid 2-FW-9) showed some evidence of wall loss. This wall reduction is believed to have resulted from cavitation damage because of the large pressure drop that exists at that location. Although three-percent wall reduction was noted, the minimum wall acceptance criteria for this fitting had not been violated, and this area will be monitored for wall reduction in the future.

The Division of Nuclear Engineering (DNE) had provided [redacted] for the areas identified for the analysis (see tables 1 and 2). The inspections showed that [redacted]

Metallurgical Inspection

Metallurgical inspections were performed on A and C trains of units 1 and 2 number 2 feedwater heaters. The locations are shown on figure 16. Both the inlet and discharge piping and fittings were inspected. The inlet piping had some superficial patterns on its wall because of direct impingement from the number 3 heater drain tank piping. No red hematite was observed on the ID, and [redacted] (see location 3, figure 16). At location 2, no red hematite or exposed base metal was observed. On the discharge piping, the results were similar. Also, there was a backing-ring that had been pushed into the flow path during original installation. It showed no signs of wear and was covered with the protective magnetite film, even though it was in a severe environment.

Discussion

UT and metallurgical inspections indicated that no EC damage or significant thinning by other means was detected, although SQN has conducive feedwater piping conditions. However, [redacted] The history of the feedwater chemistry at Surry Station is unknown. Previous inspections on the number 3 heater drain tank, the steam generator feedring header, and the feedring tee did not reveal service-induced damage. [redacted] (The J-tubes were A106 Grade B steel, but the velocities were as high 31 ft/sec.) Velocity of the 24- and 30-inch headers and fittings were 12 ft/sec and 14 ft/sec respectively (see table 3). The propensity of the EC decreases with a decrease in velocity.

Conclusions and Recommendations

The test data and inspection results indicated that EC damage had not occurred in the areas examined. The selected areas were identified as the highest probability areas. However, there may be other thinning mechanisms occurring, i.e., cavitation. The lowest readings were found on the discharge side of the feedwater pump on 24- by 16-inch reducing elbows. **None of these readings were below the design minimum wall thickness** specified by DNE. The elbows further downstream of the A and B pumps will be examined and included in the final report. **The piping upstream of the** [redacted] outage. Feedwater pH should be optimized to the highest pH attainable to **minimize the potential for EC damage throughout the balance of the plant carbon steel system.** [redacted]

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NEC-JH_71

Erosion-corrosion of carbon steels has been experienced in the steam generator and secondary water circuits of many reactor systems. Damage has occurred under both single and two-phase water flow conditions, and is associated with severe fluid turbulence at the metal surface. In the most severe cases, this can lead to very high metal wastage rates (>1mm/year), and consequently rapid component failure. The available experience, previous research and current understanding of the phenomenon are reviewed, and both experimental and theoretical work in progress at CERL is described. The pH dependence of the phenomenon under single phase conditions at 148°C is reported. and by using hydrodynamically well characterized specimens, the dependence of erosion-corrosion rate on mass-transfer has been investigated. At 148°C, the rate has been found to vary as the cube of the mass transfer coefficient. This is in agreement with the predictions of a model of the process based on the electrochemical dissolution of magnetite. In order to make quantitative measurements on the process, high precision bore metrology and surface activation of the test specimens has been used extensively, and these measurement techniques are also discussed.

INTRODUCTION

1. Nuclear steam generators have experienced a wide variety of corrosion related problems, and the vulnerability of individual designs to any particular type of corrosion damage can vary widely. In all cases, however, the economic penalties resulting from such damage are considerable, and there is therefore a strong incentive to eliminate such problems as far as possible. To this end, a wide variety of research programmes are in progress throughout the world.

2. In many nuclear systems, corrosion has resulted from the generation of aggressive solutions via solute concentration processes (ref.1). This is particularly true in the case of PWR steam generators, for example with the denting, phosphate thinning and tube sheet crevice stress-corrosion problems (ref.2).

3. In the case of U.K. gas cooled reactor steam generators, considerable effort has been directed at understanding and eliminating the possibility of corrosion damage resulting from solute concentration under two phase flow and dryout conditions, and the vulnerability of both Magnox and AGR steam generators to on-load corrosion and stress corrosion has been reviewed very recently (ref.3). The need for stringent feed-water chemical control was recognised and to date they have not proved to be a problem. However, both Magnox and AGR steam generators have been subject to an entirely different type of corrosion damage not dependent on any solute concentration process, namely erosion-corrosion. Similar erosion-corrosion problems have also been encountered in other gas cooled reactors elsewhere, most notably in France and Japan, but the problems are not restricted to gas cooled reactor steam generators, and this type of damage has occurred in the steam-water circuits of water and sodium cooled reactors. As a result there is growing international interest in erosion-corrosion phenomena (ref. 4-7). The present paper therefore attempts to summarize current experience and understanding of the problem, and describe erosion-corrosion work in progress at CERL.

EROSION-CORROSION

4. The term erosion-corrosion is slightly misleading and the phenomenon is perhaps better described as flow assisted corrosion. As such it is clearly distinguishable from pure erosion or cavitation damage.

5. Erosion-corrosion damage normally occurs at locations where there is severe fluid turbulence adjacent to the metal surface, either as a result of inherently high fluid velocities, or the presence of some feature (bend, orifice etc.) generating high levels of turbulence locally. Its occurrence is also usually associated with the use of mild or carbon steel components. The attack occurs under both single and two-phase water conditions, but not in dry steam, which is consistent with the general view that the process is essentially one of surface dissolution. It is frequently, although not invariably, characterized by the occurrence of overlapping horse-shoe shaped pits, giving the surface a scalloped appearance, as shown in Plate 1. However, these pits are normally relatively shallow in comparison to the general metal wastage in the area concerned. The oxide present on the corroding surface is normally very thin, 1 μm or less, and often exhibits a polished appearance. However, heavy oxide deposition is sometimes present on adjacent areas of tube not

PLATE 1. Erosion-corrosion damage produced under two phase conditions in a mild steel riser pipe from a Magnox steam generator. Flow from left to right.

PLATE 2. Erosion-corrosion damage downstream of the orifice in a CERL mild steel orifice assembly specimen. Flow from left to right.

OXIDE

10 μm

PLATE 3. Metallographic cross section of specimen shown in Plate 2 in region of maximum erosion corrosion loss.

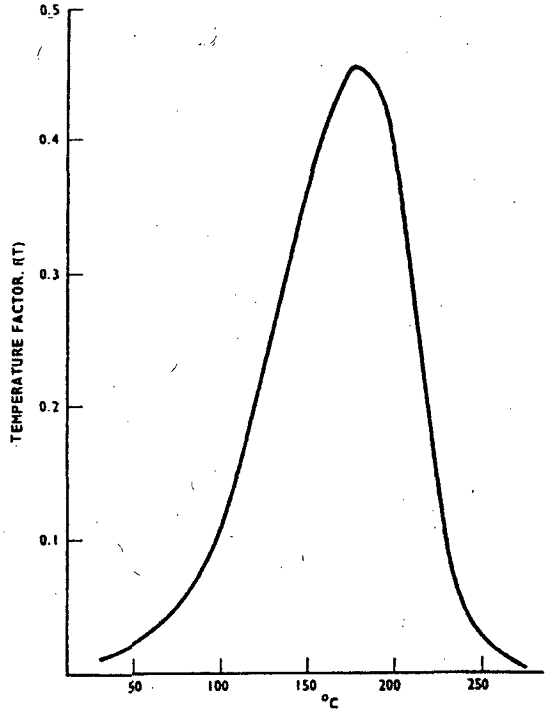

FIGURE 1. Temperature dependence of erosion-corrosion losses under two phase conditions (ref.19)

FLOW PATTERN				REFERENCE VELOCITY	K_c
PRIMARY FLOW STAGNATION POINTS	AT PIPES			VELOCITY OF INITIAL FLOW (UPSTREAM OF STAGNATION OBSTACLE)	1
	AT BLADES				1
	AT PLATES				1
	IN PIPE JUNCTIONS				1
					0.8
SECONDARY FLOW STAGNATION POINTS	R D 0 5	IN ELBOW PIPES		FLOW VELOCITY	0.7
	R D 1 5				0.4
	R D 2 5				0.3
	BEHIND PIPE JOINTS				0.2
STAGNATION POINTS DUE TO VORTEX FORMATION	BEHIND SHARP EDGED ADMISSION PIPES			FLOW VELOCITY	0.2
	AT AND BEHIND BARRIERS				0.2
NO STAGNATION POINTS	IN STRAIGHT PIPES			FLOW VELOCITY	0.04
	IN UNTIGHT HORIZONTAL TURBINE JOINTS			VELOCITY CALCULATED FROM PRESSURE DROP	0.08
COMPLICATED FLOW THROUGH TURBINE PART	IN TURBINE GLAND SEAL			VELOCITY CALCULATED FROM PRESSURE DROP	0.08
	AT AND ABOVE TURBINE BLADES AND AT DRAINAGE COLLECTING RINGS			AVERAGE CIRCUMFERENTIAL BLADE VELOCITY	0.3

FIGURE 2. Influence of flow path configuration on erosion-corrosion damage under two-phase conditions (ref.13)

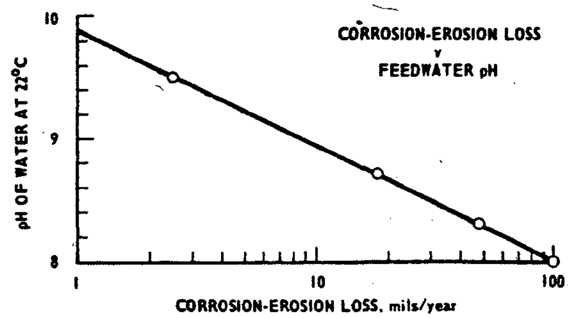

FIGURE 3. Erosion-corrosion loss rate v pH for a rotating disc at 99°C (ref.26)

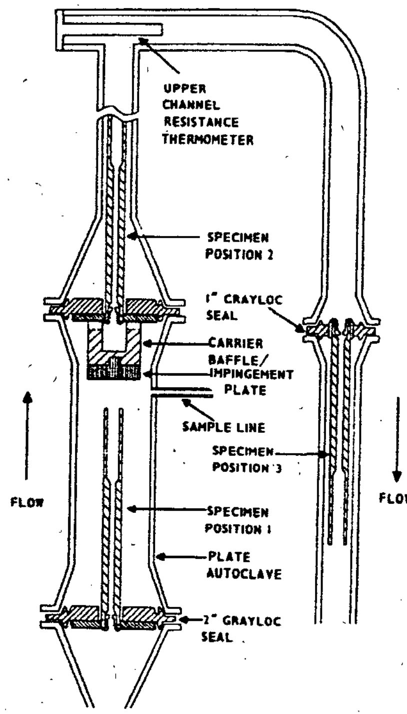

FIGURE 5. Arrangement of orifice assembly specimens in autoclave flow channels.

suffering erosion-corrosion attack, particularly under two phase conditions.

6. Under severe conditions, metal wastage rates of 1 mm/year or even higher can be observed in erosion-corrosion situations, so that component failure can be relatively rapid in the worst cases.

Plant Experience

7. Under two phase conditions, erosion-corrosion damage within nuclear steam generators has frequently occurred at tube bends, bifurcations or similar features in the steam-water circuit. Among the earliest reported instances of damage of this type were those at the Tokai Mura plant in late 1968 (ref.8,9). This station employs dual pressure drum re-circulation type steam generators, and early failures occurred at 214°C in swan neck bends and tube bifurcations at the outlet end of the mild steel L.P. evaporator tubes. Some failures also occurred at tube bends in the subsequent riser pipes to the L.P. steam drum external to the steam generator itself, and significant tube thinning was reported for the last two return bends of the serpentine evaporator tube banks inside the units. Tube wastage rates as high as 1.3 mm/year were found in some cases. Up to the time of the failures, the boilers had been operated with hydrazine/ammonia dosing to give a boiler water pH in the range 8.5 to 9.2. Some dosing with Na_3PO_4 was also employed to combat chloride ion (200-300 ppb) present in the water (ref.9).

8. Similar failures to these have occurred under steaming conditions in the mild steel economiser sections of British Magnox stations, and in the evaporator sections of once-through steam generators such as those at St. Laurent I and II. In the case of St. Laurent II, failures occurred in the 180° return bends of the mild steel serpentine evaporator towards the end of the evaporation zone, at a temperature of about 245°C (ref. 4, 10). As in the case of Tokai Mura, the boiler feedwater was originally dosed with ammonia and hydrazine to about pH 9.0. However, more recently morpholine dosing has been employed because of its lower partition coefficient between water and steam and higher basicity at high temperature, which should maintain a higher solution pH at temperature (ref.11).

9. Erosion-corrosion problems under two phase conditions have also been reported to have occurred in the steam generator units at Marcoule and Chinon 2 (ref.4, 10).

10. Erosion-corrosion damage in nuclear steam generators under single phase (water) conditions has commonly been associated with boiler feed-water tube inlets, and in particular those where orifices have been installed to control the boiler feed flow. Damage of this type has been experienced at St. Laurent II, with an inlet feedwater temperature of about 125°C (ref. 4,10), and at somewhat higher temperature (up to 246°C) in the case of the Phenix steam generators (ref. 5, 10). In the case of Hinkley Point 'B' Power Station, erosion-corrosion damage at the feedwater inlets downstream of the flow control orifices was compounded by flow bypassing through the gap between the threaded ends of the restrictor tubes and the orifice carriers (ref.12). In some cases this fluid bypassing completely eroded away the restrictor tube end.

11. In addition to problems within the steam generators themselves, erosion-corrosion damage has frequently been encountered in wet steam turbines (ref.13) and associated steam pipework (ref.6), both the feedwater and steam-side of feed heaters (ref.14-17) and boiler feed pumps (ref.7). Clearly therefore the problems are very widespread, and not restricted to any one type of nuclear plant.

Current Understanding of Erosion-Corrosion Behaviour

12. In spite of the widespread occurrence of erosion-corrosion problems, as outlined in the preceeding section, relatively little experimental or theoretical work on the subject has been reported in the open literature. It is clear, however, that erosion-corrosion behaviour depends on a number of physical and chemical variables. These are principally; materials' composition, local hydrodynamic conditions including the effects of steam quality, temperature and water chemistry. Any model of the process should therefore be capable of explaining the detailed dependence of erosion-corrosion on these parameters. Their general influence on erosion-corrosion behaviour under boiler feed-water conditions is summarised below.

13. Materials' Composition. Erosion-corrosion damage is most frequently observed when carbon or mild steel components are employed. Alloy steels, particularly chrome alloy steels are much less susceptible to erosion-corrosion attack, and austenitic stainless steels essentially immune to damage. Relatively small amounts of chromium in the steel improve its erosion resistance quite markedly, although the degree of improvement appears to depend on the severity of the conditions. Thus in tests at 120°C, involving impingement of a water jet on the sample surface at 58 ms^{-1}, 2% Cr steel was found to be at least an order of magnitude more resistant to damage than carbon steel, with higher chrome steels even more resistant (ref.18). However, practical experience with wet steam turbines and their associated pipework suggests 2¼% Cr steel to be about four times more resistant to attack than mild steel, whilst 12% Cr steel has proved to be virtually unaffected (ref.13).

14. It is likely that other minor alloying or trace elements such as copper, nickel, manganese and silicon would influence resistance to erosion-corrosion as such elements are known to affect corrosion resistance of carbon and low alloy steels to a wide range of aqueous environments. However, there appears to be no systematic studies reported in the open literature.

15. Temperature. Erosion-corrosion damage is most prevalent in the temperature range 50° to 250°C. Fig. 1 shows the effect of temperature on relative erosion rates based on data derived from damage occurring under two phase conditions in wet steam turbines (ref.19). This indicates maximum damage to occur at around 180°C. However, more recently it has been proposed that under single phase conditions, the maximum is close to 140°C (ref.20). Limited studies on the effects of temperature under single phase conditions have also been reported by Decker, Wagner and Marsh (ref.21) which would appear to support this, but there remains some uncertainty in the precise variation of erosion-corrosion rates with temperature. For example, rapid two phase erosion damage has frequently been observed at temperatures well in excess of 200°C (e.g. St. Laurent II), whereas the curve in Fig. 1 would suggest the problem to be disappearing rapidly at these temperatures.

16. Hydrodynamics. Erosion-corrosion damage has in general been observed at points of hydrodynamic disturbance in the fluid flow. Under single phase conditions damage has frequently occurred at tube entries in preheaters, or downstream of orifices at boiler tube entries, whereas under two phase conditions the damage has often been associated with bends. Keller (ref.19) has attempted to rationalize the effects of various flow path configurations on erosion-corrosion damage under two phase conditions by use of an empirical damage factor (K_c) together with a reference flow velocity. These are given in Fig. 2. However, it is doubtful that these parameters can be equally well applied to damage under single phase conditions as a result of the differing hydrodynamic flow patterns which would occur. More recently at CERL and elsewhere (ref.7) attempts have been made to relate erosion-corrosion rates in single phase water to local mass transfer rates, and these will be discussed subsequently.

17. In view of the critical dependence of erosion-corrosion damage on fluid flow and turbulence, it is surprising that no detailed studies have been reported of the effect of flow velocity and turbulence on erosion-corrosion rates. Some studies have been made at high temperature (>280°C) (ref.22-24), but these are outside the range normally associated with erosion-corrosion attack.

18. Water Chemistry. Several aspects of water chemistry are thought to influence erosion-corrosion behaviour. The effect of pH and oxygen content of the water have been examined, but other components such as hydrazine and dissolved iron are also expected to exert a significant influence on the process (ref.25).

19. Most instances of erosion-corrosion damage have occurred with a deoxygenated volatile alkali dosed water chemistry.

20. In studies of erosion-corrosion damage in feed heaters (ref.14,15), it was found that attack occurred predominantly when the feedwater pH was less than 9.0, but attack was not normally observed with pH >9.2. Similarly, the occurrence of erosion-corrosion damage in wet steam turbines has been reported to occur only when the condensate pH is below about pH 9.4 (ref.13,19).

21. The effect of pH on erosion-corrosion rates has been studied experimentally by Apblett (ref.26) using a rotating carbon steel disc over the pH range 8.0 to 9.5 at 99°C in deaerated water. The results are shown in Fig. 2, and indicate a tenfold reduction in wastage rate on increasing the pH from pH 8 to 9. Similar reductions in rate have also been reported for jet impingement studies at 120°C (ref.27).

22. The effect of oxygen on erosion-corrosion behaviour as such has not been studied in great detail. However, iron release rates from carbon steel in neutral water at 1.85 ms^{-1} over the temperature range 38° to 204°C have been shown to decrease by up to two orders of magnitude with increasing oxygen content over the range <1 to 200 ppb (refs.23, 28-31). It is to be expected that erosion-corrosion will at least qualitatively follow this type of behaviour.

23. Additions of up to 300 ppb oxygen (or more commonly hydrogen peroxide) to neutral feedwater forms the basis of the neutral oxygen low conductivity (NOLC) water chemistry regime used by a number of power utilities for fossil fired once thro' boilers (ref.32), and these are evidently largely free from erosion-corrosion damage. More recently, it has been reported that combined NH_3/H_2O_2 dosing of feedwater is also effective in this respect (ref.33).

Models of Erosion-Corrosion Behaviour

24. Keller (ref.19) has proposed an empirical equation for predicting erosion-corrosion losses from carbon steel, based on observations in wet steam turbines. This has the form

$$s = f(T).f(x).c.K_c - K_s \qquad (1)$$

where s is the maximum local depth of material loss in mm/10^4 hours.

f(T) is a dimensionless variable denoting the influence of temperature on erosion-corrosion damage. A plot of f(T) is shown in Fig. 1.

f(x) is a dimensionless variable denoting the influence of steam wetness on erosion-corrosion loss. For sub-cooled water it has been suggested that this has a value of unity, but for two phase mixtures it has the form $f(x) = (1 - x)^{K_x}$, where x is the steam fraction and $0 << K_x < 1$. A value of $K_x = 0.5$ is evidently considered the most appropriate one.

K_c is a variable factor accounting for the effect of local geometry on the fluid flow. Values of K_c in mm.s/m 10,000 hours are

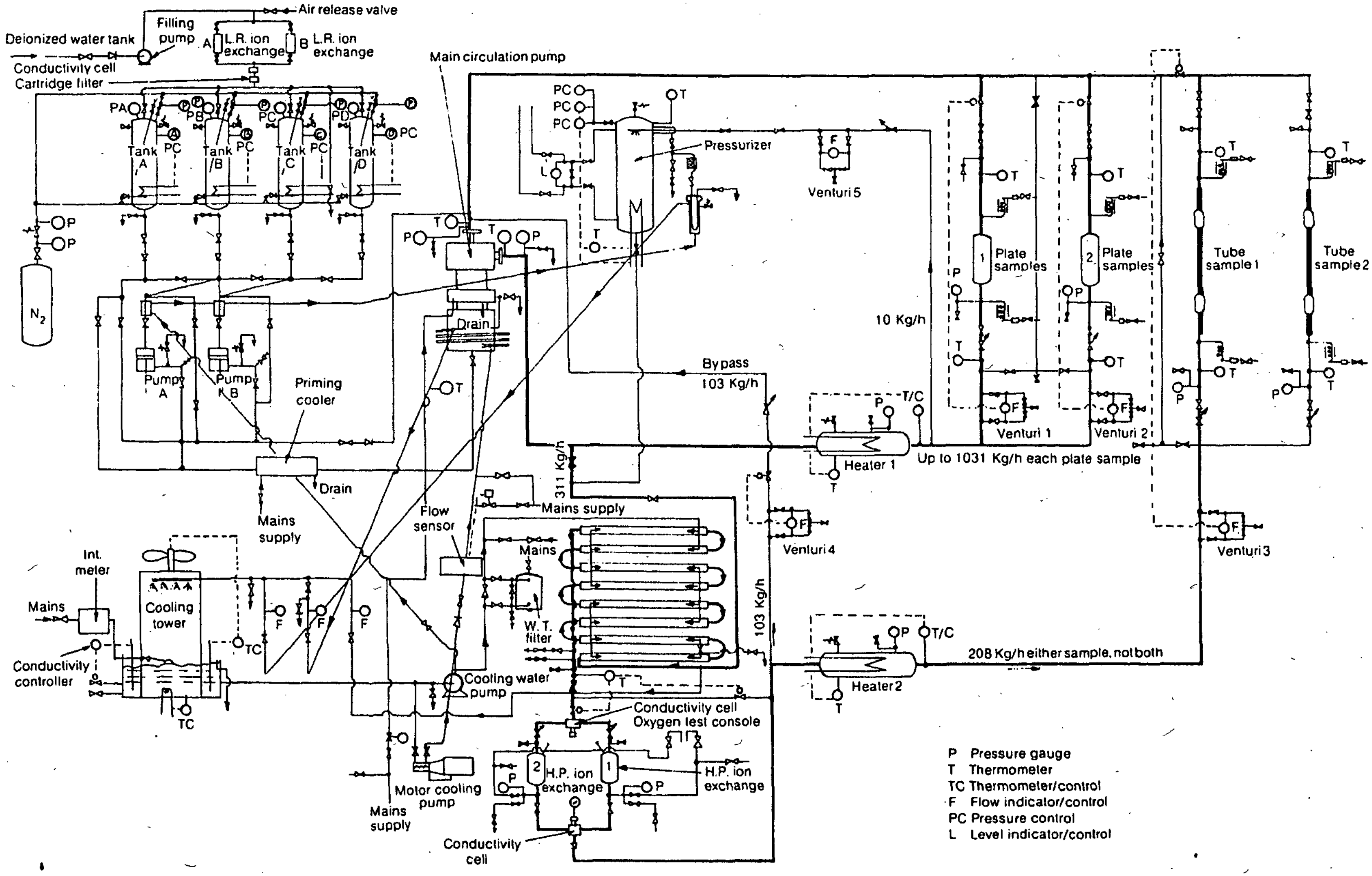

FIGURE 4. Isothermal Rig flow diagram

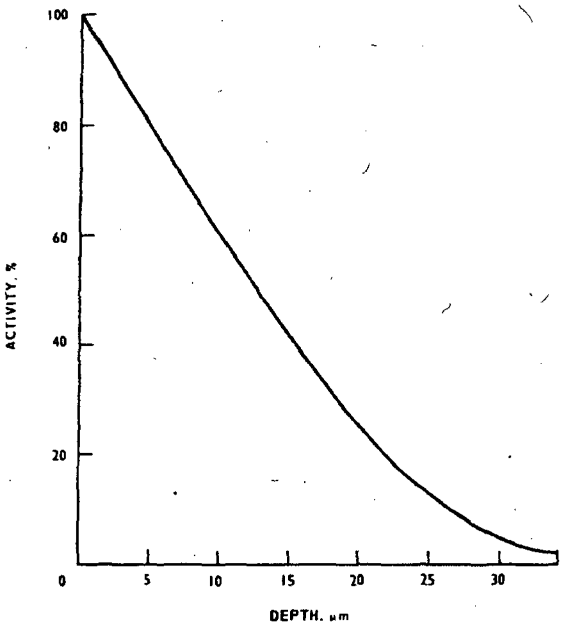

FIGURE 6. Activity/depth curve for ^{56}Co produced in an iron matrix by a 10.8 MeV proton beam inclined at 10° to the surface

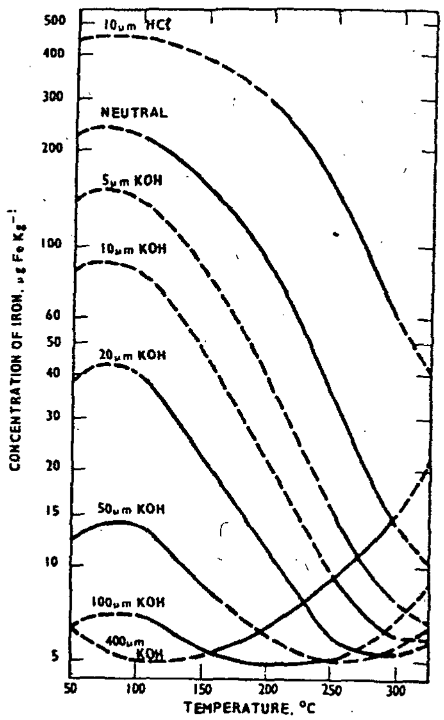

FIGURE 8. Variation of magnetite solubility with temperature and pH at 1 bar hydrogen partial pressure. (Ref. 42)

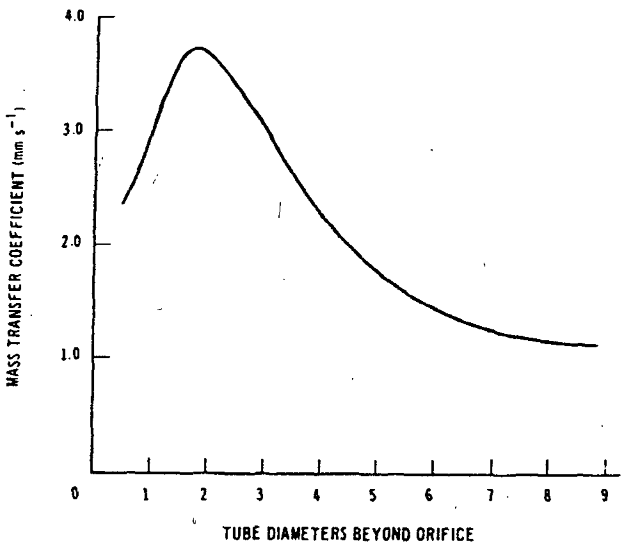

FIGURE 7. Variation of mass transfer coefficient in a tube downstream of an orifice

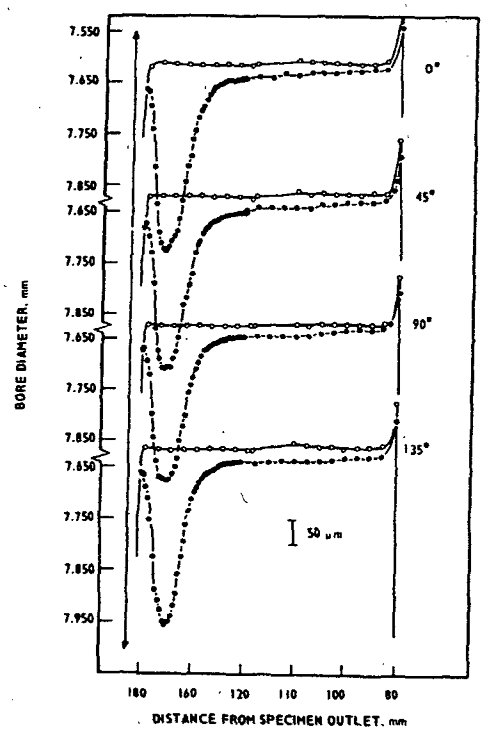

FIGURE 9. Erosion-corrosion loss profile in tube downstream of an orifice (Diametral circumferential locations shown. Orifice located 185 mm from specimen outlet)

given in Fig. 2.

c is the fluid velocity in ms^{-1}.

K_s is a constant which the first term must exceed before erosion-corrosion is observed. A value of 1 mm/10^4 hours has been given by Keller (ref.19).

Equation (1) does not include any influence from changes in water chemistry, although as indicated earlier, these have a very marked effect on the rate and occurrence of erosion-corrosion damage. It is also very doubtful that it can be applied in its present form to single phase erosion-corrosion damage, since many instances of damage have occurred under single phase conditions which would not have been predicted by equation (1).

25. Discussions of some mechanistic aspects of erosion-corrosion attack has been given by Homig (ref.34) and Bohnsack (ref.35), who concluded that the process is due to dissolution of the metal surface to give Fe^{2+} ions in solution, which are continually removed by the turbulent fluid flow. However, both these authors restrict themselves largely to discussion of the dissolution at 25°C, which is well below the temperatures at which erosion-corrosion attack is normally encountered. At 25°C, $Fe(OH)_2$ is normally considered to be the corrosion product involved in the dissolution process in deoxygenated water, but at temperatures higher than about 100°C, this is converted to Fe_3O_4 via the Schikorr reaction:

$$3\ Fe(OH)_2 \rightarrow Fe_3O_4 + 2H_2O + H_2 \qquad (2)$$

The rate of this reaction increases with temperature, and magnetite is typically the phase observed on surfaces undergoing erosion-corrosion attack at temperatures above about 120°C. As a result, erosion-corrosion attack at these higher temperatures has been attributed to rapid dissolution of the unstable $Fe(OH)_2$ intermediate (ref.36).

26. Very recently attempts to produce a model of erosion-corrosion based on calculated mass transfer rates and the solubility of magnetite have been made by Gülich et al. (ref.7). Work to produce a more satisfactory model is also in progress at CERL, and this is outlined in subsequent sections. However, at present there is no completely satisfactory model of erosion-corrosion behaviour which is capable of rationalising the effect of all the diverse factors influencing the process.

CERL EROSION-CORROSION STUDIES

27. The work currently in progress at CERL on erosion-corrosion is directed at establishing a consistent set of experimental data from which it is possible to make accurate predictions of plant behaviour, and to develop a satisfactory theoretical model of the process capable of rationalizing the experimental work. At present, both experimental and theoretical studies are concerned entirely with erosion-corrosion in single phase water, although it is to be hoped that the results of the work can be applied with certain limitations to erosion-corrosion behaviour under two-phase conditions.

Experimental Facility

28. Experimental studies of erosion-corrosion are being carried out using a high velocity isothermal water circulation loop, referred to as the isothermal rig for short (ref.37). This facility consists basically of a main circulation loop, a secondary water clean up loop and a pressurizer loop, together with ancillary make-up/dosing and chemical sampling systems. A flow diagram for the rig is shown in Fig. 4.

29. Four specimen flow channels are incorporated in the rig, two specimen autoclaves in the main loop, and two tube specimens within the secondary polishing loop.

30. The rig is principally constructed of Type 316 stainless steel, with the exception of the pressurizer vessel (2¼ Cr 1 Mo ferritic steel), the heater elements (Inconel) and some parts of the main circulating pump (Incoloy 825, stellite and ferobestos). The rig is designed to operate over the following range of physical conditions:

Temperature,	up to 350°C
Pressure,	up to 21.78MNm^{-2}(3160 lbf in^{-2})
Autoclave flowrates,	up to 1031 kg h^{-1} per autoclave
Tube specimen flowrate,	up to 208 kg h^{-1} total
Bypass flowrate,	up to 103 kg h^{-1}
Pressurizer flowrate,	up to 20 kg h^{-1}

Once the rig water has been pressurized and water circulation achieved using the main pump, control of the physical operating parameters of the rig is largely automatic, with the variables of interest (flow rate, temperature, pressure, water level etc.) being recorded by a dedicated CAMAC data logger.

31. The rig incorporates four methods for controlling the water chemistry, namely ion exchange, chemical dosing, blowdown and deaeration. Data on the chemical composition of the water within the rig is derived mainly from continuous chemical monitoring of sample streams which can be drawn from a large number of different sampling points around the rig. The exception to this is the direct measurement of conductivity before and after the ion-exchange columns. To date, all the experimental work carried out on the rig has been with an ammonia dosed deoxygenated water chemistry regime, and for these conditions it has been found convenient to work with the cation exchange resins of the mixed bed ion-exchange columns converted to their ammonium ion form.

32. In its present form, the rig is capable of operating within the following limits of physical and chemical control parameters.

Temperature at test specimens	± 1°C
Flow to test specimens	± 1%
pH of circulation water*	± 0.1 pH unit
Conductivity of water after cation exchange+	< 0.6 μS cm^{-1}
Dissolved iron in circulating water at 148°C	< 10 μg kg^{-1}
Dissolved active silica in circulating water at 148°C	< 10 μg kg^{-1}
Dissolved oxygen in circulating water at 148°C	< 6 μg kg^{-1}

* Dependent on pH of circulating water, values given for pH 9.0. At higher pH, the precision of pH control improves, and dissolved Fe levels fall.

\+ Upper limit of conductivity, due to very slow sampling rate.

Test Specimens

33. A variety of erosion-corrosion test specimens can be incorporated into the isothermal loop, using both the autoclave and tube specimen flow channels.

34. The tube specimen channels are provided with couplings for the attachment of tubing between two points 2 m apart. Initially straight 3 mm bore mild steel test specimens and stainless steel dummy specimens have been incorporated, but it is possible to incorporate bent tubes, bore expansions and constrictions and a variety of other options in this area of the rig.

35. Four plate type specimens, 195 x 12 x 1 mm can be incorporated into each of the autoclave flow channels using stainless steel specimen holders. These hold the specimens with a 1 mm gap between them, and allow rig water to flow along their length. However, it is possible to incorporate other types of test specimens in the autoclave flow channels, and most of the work to date has involved the use of orifice assembly specimens. Up to three such assemblies can be accommodated in each autoclave flow channel, as shown in Fig. 5. To minimise interaction between specimens in series with one another, a baffle plate can be inserted, as shown in Fig. 5, and this also serves as an impingement specimen. It is possible to incorporate up to three orifice assemblies in parallel on the inlet Grayloc seal of the autoclave, and in this way interactions between adjacent tubes could be studied, in addition to increasing the total number of specimens. This does, however, reduce the flow through any one specimen to one third of that through the specimen on the autoclave outlet Grayloc seal.

36. The advantage of using this type of orifice assembly is that experiments can be performed on specimens which accurately simulate plant components, and which are well characterised hydrodynamically. They can therefore be used for precise correlation of erosion-corrosion and mass transfer behaviour (see subsequent discussion). The particular specimens used permit behaviour to be studied at five different potential erosion-corrosion sites; the tube inlet, the jet reattachment zone downstream of the orifice, downstream of a tube expansion, and in two different diameter straight tube sections (i.e. two different flow velocities). The specimens also have the advantage that being essentially straight tube test pieces, it is possible to use high accuracy bore diametral measurements to characterize the erosion loss profile throughout the specimen.

Erosion-Corrosion Monitoring Methods

37. Simple weight change measurements are possible on all the test specimens described, except the tube specimen channels themselves. However, most of the effort to date has been concentrated on monitoring damage produced in the orifice assembly specimens, and this has been done principally by the use of high accuracy bore diametral measurements, and thin layer surface activation methods.

38. Bore Metrology. Measurements of bore diameter have been made on test specimens using a "Diatest" internal bore measuring instrument. This instrument permits diametral measurements to be made with a precision of ±1 μm, and on a uniform tube surface, the reproducibility was better than ±2 μm. The tubes used in the present work are typically either drawn, or machined from bar material and have a honed surface finish. In both cases, the quality of the tubes used is sufficiently good to permit measurements to be made with the reproducibility quoted above.

39. On non-uniform tubes, or heavily eroded surfaces where the diameter changes rapidly, the reproducibility of measurement is reduced, principally due to the relatively poor longitudinal precision (±0.5 mm) with which measurements are made at present. Measures are currently in hand to improve this by using an automated measuring procedure. Nevertheless, in all cases to date it has been possible to produce highly accurate bore loss profiles from the test specimens.

40. Surface Activated-Specimens. Erosion-corrosion losses of a number of specimens have been monitored in situ by the use of thin layer activation of the specimen. To date this has only been employed with orifice assemblies, but can in principal be used for any type of specimen.

41. The technique consists of activating to a known depth an area of the specimen surface by high energy charged particle bombardment (ref.38). Metal loss from the specimen can then be determined by monitoring the loss in activity from the specimen surface as erosion-corrosion proceeds. In the present work, small areas of the internal tube surface (5 to 10 mm x 1.75 mm) have been activated by bombardment with 10.8 MeV protons at angles of 10° or 20° to the tube surface.

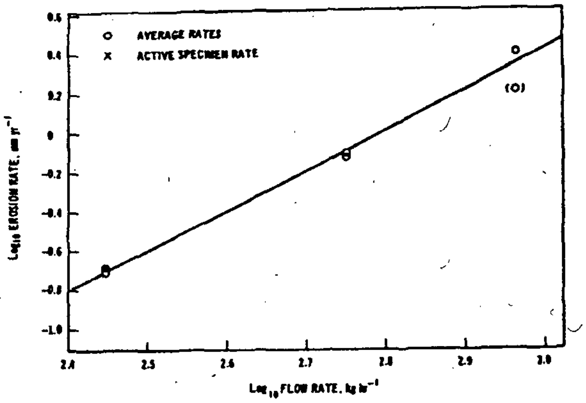

FIGURE 10. Velocity dependence of maximum erosion-corrosion rate observed downstream of an orifice at 157°C, and pH 9.05

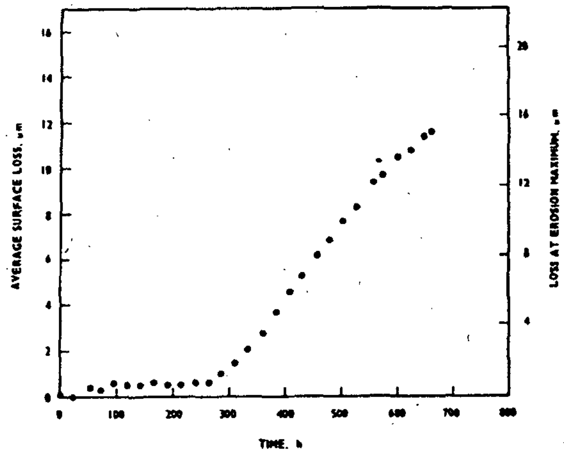

FIGURE 12. Time dependence of erosion-corrosion loss for a surface activated specimen.

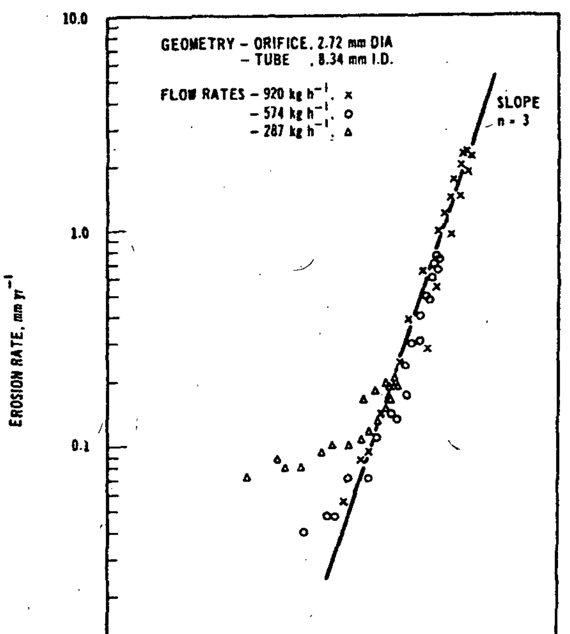

FIGURE 11. Correlation of erosion corrosion rate downstream of orifice with corresponding mass transfer coefficient throughout the erosion-corrosion zone

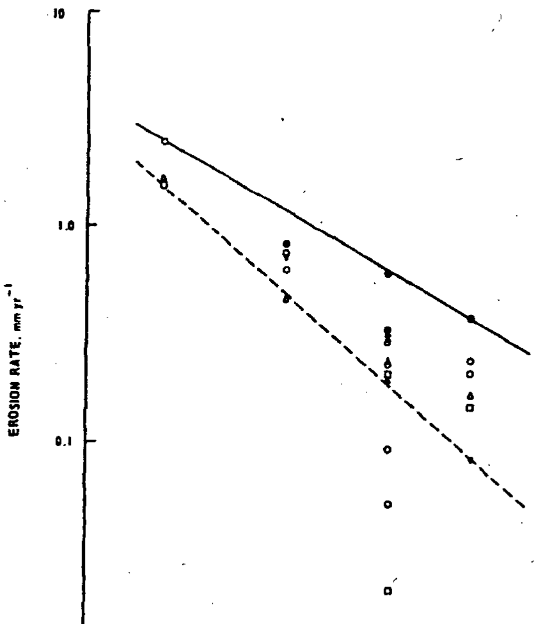

FIGURE 13. pH dependence of erosion-corrosion rates at 157°C. Solid symbols, maximum rates from surface activated specimens, open symbols average rates

The bombardment of ^{56}Fe with high energy protons produces ^{56}Co which has a half-life of 77.3 days, and the principal γ-ray emitted on decay has an energy of 845 keV. The maximum depths of activation for bombardment with protons at 10^{o} and 20^{o} are around 35 and 70 μm respectively. Deeper activation is possible by bombarding normally to the tube surface, or by increasing the incident proton energy. The total ^{56}Co activity versus depth curve for bombardment at 10^{o} to the tube surface is shown in Fig. 6.

42. Loss of material from the specimen surface has been determined in-situ by monitoring the γ-ray emissions from the sample using a scintillation detector placed in close proximity to the autoclave containing the active specimen. These have permitted measurements of erosion loss to be made as a function of time with an accuracy of ±0.1 μm in the case of an activation depth of 35 μm.

43. Full details of the experimental technique will be reported elsewhere (ref.39).

Theoretical Work

44. If erosion-corrosion is controlled solely by the rate of mass transfer of Fe from the eroding surface, then the erosion-corrosion rate may be expected to vary according to

$$\frac{dm}{dt} = K(C_s - C_b) \qquad (3)$$

Where K = mass transfer coefficient

C_s = concentration of iron in solution at the oxide-solution interface

C_b = concentration of iron in the bulk solution

$\frac{dm}{dt}$ = rate of metal loss.

45. The value of the mass transfer coefficient K varies with the local hydrodynamic conditions. Its dependence on these is usually expressed in dimensionless form using the corresponding Sherwood number Sh, where Sh = KD/*D*, D = duct diameter and *D* = diffusion coefficient for iron in solution. This is normally expressed in terms of the Reynolds (Re) and Schmidt (Sc) numbers in empirical correlations of the form

$$Sh = \alpha Re^{\beta} Sc^{\gamma} \qquad (4)$$

where α, β and γ are constants determined by experiment; γ typically has a value around 1/3, whilst the value of β is usually in the range 2/3 to 7/8. Correlations of this type are already available for a number of hydrodynamic situations of concern in erosion-corrosion, and two of particular interest in the present work are those for turbulent flow in straight pipes (ref.40), and downstream of an orifice (ref.41). These have the form:

Straight pipes: $Sh = 0.0165\ Re^{0.86} Sc^{0.33}$ (5)

Downstream of an orifice: $Sh_{max} = 0.27\ Re_N^{0.67} Sc^{0.33}$ (6)

where Sh_{max} in equation (6) refers to the maximum Sherwood number observed downstream of the orifice, and Re_N the orifice Reynolds number. The overall variation of mass transfer coefficient K in the tube downstream of the orifice is illustrated in Fig. 7.

46. The value of C_b in equation (3) may clearly be determined experimentally for any given erosion-corrosion situation, and for most situations of practical interest will be very low, probably less than 10 μg kg^{-1}. However, the concentration of iron in solution at the oxide-solution interface cannot be so easily evaluated. In the first instance, it might be assumed that this term may be equated with the equilibrium solubility of the surface oxide, which at temperatures above about 100°C is usually taken to be magnetite. If however some metastable intermediate oxide such as $Fe(OH)_2$ is invoked, then a different solubility would be appropriate.

47. The solubility of magnetite is known to be dependent on temperature, pH and hydrogen partial pressure (ref. 42). Fig. 8 shows the variation in magnetite solubility with pH and temperature at 1 bar partial pressure of hydrogen (1585 μg kg^{-1}) derived from the data of Sweeton and Baes. However, these solubilities are much higher than would be anticipated in operating plant, where the partial pressure of hydrogen would be much lower (∿1-5 μgkg^{-1}). Under these circumstances the equilibrium solubility of magnetite, when taken with the expected mass transfer coefficients is far too low to explain the observed erosion-corrosion rates (ref.43). This analysis would indicate that the solubility of the surface oxide is much higher than that expected for magnetite in equilibrium with the bulk partial pressure of hydrogen. It is possible, however, that the solubility may be sufficiently enhanced locally by the high equivalent partial pressure of hydrogen which results from the high local corrosion rate. Once established, the high local solubility in turn assists in maintaining the high erosion rate. Electrochemically this is equivalent to the dissolution process occurring at relatively negative potentials, which is in agreement with the general observation that actively eroding areas are normally covered with magnetite, whereas nearby non-eroding surfaces are frequently covered with haematite. This possibility may be analysed theoretically in the following manner:

48. At equilibrium, the dissolution of magnetite to form Fe^{2+} ions in solution (the dominant species under the conditions of interest) may be expressed as:

$$Fe_3O_4 + 2H_2O + 2H^+ + 2e \rightleftarrows 3Fe(OH)_2 \rightleftarrows 3Fe^{2+} + 6OH^- \qquad (7)$$

for which the appropriate Nernst-equation is

$$E = E^{\theta} - \frac{RT}{2F} \ln \frac{[Fe(OH)_2]^3}{[H^+]^2} \qquad (8)$$

which gives

$$\left[Fe^{2+}\right] = \frac{\left[H^+\right]^{8/3}}{K_2} \exp\left\{\frac{-2F(E - E^{\Theta})}{3RT}\right\} \qquad (9)$$

$$\text{where } K_2 = \frac{\left[Fe(OH)_2\right]\left[H^+\right]^2}{\left[Fe^{2+}\right]}$$

The cathodic current i_c of the corrosion reaction resulting from hydrogen discharge at the surface of the magnetite film may be expected to vary exponentially with the surface potential E of the film, as follows:

$$i_c = - FB \exp\left(-\frac{\beta FE}{RT}\right) \qquad (10)$$

If the anodic current i_a at this potential is limited by the rate of removal of Fe^{2+} ions from the surface, and since $i_a + i_c = 0$,

$$2\ FK\left\{\left[Fe^{2+}\right] - C_b\right\} = FB \exp\left(-\frac{\beta FE}{RT}\right) \qquad (11)$$

If $C_b << \left[Fe^{2+}\right]$ and $\beta = 1$ then substituting from equation (9) and eliminating E gives

$$\left[Fe^{2+}\right] = \frac{4K^2\left[H^+\right]^8}{K_2{}^3B^2} \exp\frac{2FE^{\Theta}}{RT} \qquad (12)$$

In this case the Fe^{2+} solubility of magnetite at the surface is dependent on the square of the mass transfer coefficient K, giving an overall dependence of the erosion rate on the cube of the mass transfer coefficient, through equation (3).

49. This treatment may be extended to include all soluble iron species under the conditions of interest, and the effects of a non negligible bulk concentration of iron. The expressions become more complex in this case, but still indicate a dependence of erosion-corrosion rate on the cube of the mass transfer coefficient (plus smaller terms in K^2 and K). Further analysis of the mechanistic aspects of erosion-corrosion is still under consideration, but this rather unexpected dependence of the rate on the cube of the mass transfer coefficient is born out by experiment.

Results

50. Plate 2 shows the erosion-corrosion zone downstream of the orifice generated in a mild steel orifice assembly test specimen. Although the surface loss at the erosion maximum is relatively large (~150 μm), scalloping of the surface, of the type shown in Plate 1 has not yet developed. However, the oxide film present in the eroded area is extremely thin, as shown in Plate 3.

51. In the case of specimens undergoing very rapid erosion-corrosion wastage, the films are sufficiently thin to exhibit interference colours. With lower erosion-corrosion rates, however, the eroding surface is black, as for non-eroding areas of the tube surface.

52. Micropitting of the tube surface to a depth of about 5 μm is evident in the erosion zone shown in Plate 3, and this is associated with accelerated attack of the pearlite grains of the steel. Effects of this type have also been observed in plant specimens.

53. Most of the work to date has involved the use of mild steel orifice assembly specimens, and Fig. 9 shows a typical erosion-corrosion loss profile downstream of the orifice, obtained using the bore measuring technique outlined previously. The general similarity to the mass transfer profile shown in Fig. 7 is immediately apparent. However, it is clear that the straight tube losses are quite small, whereas Fig. 7 shows the mass transfer coefficient decays asymtotically to that appropriate to the straight tube, which is about 1/3 to 1/4 of that at the mass transfer maximum. It is important to note however, that the maxima in both curves occurs approximately 2 tube diameters beyond the orifice.

54. Experiments exposing several specimens at different flow rates under the same conditions may be used to establish the flow and hence mass transfer dependence of the erosion rate, and Fig. 10 shows the velocity dependence obtained at 148°C using pairs of specimens at three different flow rates. The slope the plot indicates a V^2 dependence of erosion rate on flow, which according to equation (6) would indicate a dependence on mass transfer coefficient cubed. Further confirmation of this K^3 dependence is shown in Fig. 11, where the erosion loss profiles of individual specimens have been compared point by point with the corresponding mass transfer profile of the type shown in Fig. 7. From this it is seen that not only do the maximum losses downstream of the orifice conform with the K^3 dependence, but the erosion-corrosion rates over nearly the whole profile of the specimens correlate with K^3.

55. Whilst this alone does not substantiate the theoretical treatment outlined in the previous section, it does provide strong support for the type of mechanism invoked, and indicates that further development of the theory along these lines should prove very fruitful.

56. Fig. 12 shows the erosion-corrosion loss of an orifice assembly specimen downstream of the orifice as a function of time, determined from the activity loss of a surface activated spot in the erosion-corrosion zone. It is evident that under the particular conditions used, there is a substantial initiation time before any erosion-corrosion loss is observed. Once initiated, the erosion-corrosion rate rose rapidly to a high value, and then remained constant for most of the remainder of the test (the reduction in rate towards the end of the

test shown in Fig. 12 is thought to be due to changes in experimental conditions). This type of behaviour has been observed on a number of occasions, although the initiation time can vary widely with the experimental conditions, generally being much shorter under more aggressive erosion-corrosion conditions. The cause of such initiation periods is not certain at present. In some cases this most likely represents the time taken to remove a thin oxide film produced during start-up of the rig, when specimens are exposed to low flow for a few hours. In other cases it is thought that thin air formed oxides produced during welding of the test specimens were responsible. However, in some cases, an initial loss of a few microns has been observed, after which no loss has occurred for up to 200 hours, before true erosion-corrosion attack has been initiated with a continuing linear loss as a function of time. This would suggest that initiation is more complex than simply removing a pre-existing oxide film, and may indicate changes occur in initially formed films under erosion-corrosion conditions.

57. The pH dependence of erosion-corrosion rates has also been investigated using orifice assemblies and Fig. 13 shows the results obtained at 148°C. The upper limit of the data is essentially derived from the maximum linear rates observed using surface activated specimens. The rates derived from other specimens are average rates, which are in general lower as a result of a significant but unknown initiation time. The erosion-corrosion rates decrease by a factor of about 7 over the pH range 9.05 to 9.65, which is equivalent to a variation with $[H^+]^{1.4}$. This is a somewhat higher dependence than that seen by Apblett (ref.26) at 99°C, where the erosion-corrosion rate varies as $[H^+]^{1.0}$.

SUMMARY

58. Corrosion resulting from salt concentration caused by evaporation continues to be a major cause of steam generator damage, particularly in PWRs and has been the subject of intense international research. Erosion-corrosion damage has occurred in a wide variety of nuclear steam generators, but unlike corrosion resulting from solute concentration, relatively little work on the problem has been reported in the open literature. The available experience, previous research and current understanding of the phenomenon have been reviewed, and CERL research on the subject summarized.

59. The CERL isothermal loop has been used to study erosion-corrosion behaviour under single phase conditions comparable with those which occur in plant. By using test specimens which are well characterised hydrodynamically, it has been possible to accurately correlate erosion-corrosion rates with the corresponding mass-transfer rate. Under the particular conditions used (148°C, pH 9.05), it has been found that the rate varies as the cube of the mass-transfer coefficient. This unexpected result is explicable, however, in terms of an electrochemically based model of magnetite dissolution.

60. Since mass-transfer coefficients can be calculated for a wide variety of hydrodynamic situations, at least under single phase conditions, it should be possible to use correlations of this type to predict plant behaviour over a wide range of conditions.

61. Increasing pH has been shown to markedly reduce erosion-corrosion rates over the range 9.05 to 9.65, in agreement with other studies of the effect at lower temperatures. In many plant situations, therefore, this option should prove effective in controlling erosion-corrosion damage. It is likely to be especially useful when other options such as materials change or oxygen addition are not feasible.

62. Details of the mechanism of erosion-corrosion damage have still to be established, but the use of surface activation in the present work has proved to be extremely valuable for monitoring losses in-situ. Using this technique it has been possible to establish the linearity of erosion-corrosion loss as a function of time, after some initiation period, and it will undoubtedly be useful in studying erosion-corrosion behaviour under transient conditions. In conjunction with electrochemical techniques, therefore, it should prove very valuable in elucidating aspects of the corrosion mechanism.

ACKNOWLEDGEMENTS

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Paper 96. The influence of oxygen and hydrazine on the erosion-corrosion behaviour and electrochemical potentials of carbon steel under boiler feedwater conditions

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In the temperature range 100 to 250°C, carbon steel is highly susceptible to erosion-corrosion damage in deoxygenated boiler feedwater when mass transfer coefficients are sufficiently high. The erosion-corrosion process can be completely inhibited by addition of low levels of oxygen to the feedwater, but experiments have shown that the process continues essentially unaffected below a critical oxygen threshold. The oxygen level required to inhibit the process depends on the local oxygen mass transfer coefficient to the eroding surface, and the existing metal loss rate. An upper limit for the threshold concentration can be derived from the rate of oxygen mass transfer to the surface required to match the ongoing erosion-corrosion rate. Under these circumstances, the cathodic current normally supplied by the hydrogen evolution reaction can be substituted by an equivalent one due to oxygen reduction. When the critical rate of oxygen mass transfer to the surface required to inhibit erosion corrosion is achieved, the surface electrochemical potential shifts several hundred millivolts positive of that previously maintained. Oxygen has been shown to inhibit erosion-corrosion and control the electrochemical potential of carbon steel even in the presence of large excesses of reducing agents such as N_2H_4 and H_2, at temperatures up to 250°C. However, removal of the oxygen by reaction with hydrazine allows the erosion-corrosion process to re-initiate rapidly. Hydrazine alone does not significantly influence the potential of actively eroding surfaces, but does appear to reduce the erosion-corrosion rate as a result of the increased high temperature pH.

INTRODUCTION

1. In the temperature range 100 to 250°C, carbon steel is highly susceptible to erosion-corrosion damage in deoxygenated boiler feedwater if fluid velocities and hence mass transfer coefficients are high enough (ref. 1). However, oxygen in the feedwater has an inhibiting effect on the erosion-corrosion process (ref. 2 to 5), to the extent that when oxygen levels are high enough, the attack is completely suppressed. However, the exact amount of oxygen required, in general, to inhibit the process under a given set of conditions has not been established.

2. Various feedwater chemistries have been developed in recent years which utilise oxygen dosing at some level which would be expected to be successful in suppressing erosion-corrosion damage under single phase flow conditions. The NOLC, Neutral Oxygen Low Conductivity (ref. 6) and Combined Oxygen-Ammonia (ref. 7) water chemistry regimes employ relatively high levels of oxygen in the feedwater, without or with ammonia dosing respectively. Specifications for the NOLC regime require >50 $\mu g\ kg^{-1}$ oxygen (ref. 6), whilst the combined regime has been optimised with oxygen levels in the range 150 to 300 $\mu g\ kg^{-1}$ and ammonia dosing to give a pH_{25}°C between 8.0 and 8.5 (ref. 7). However, a variation of the combined regime adopted for CEGB gas cooled reactor once-through boilers employs much lower levels of oxygen dosing, 15 $\mu g\ kg^{-1}$, with a pH_{25}°C from ammonia >9.3. It removed in the higher temperature sections of the boiler. This is to eliminate its possible influence on corrosion in the 9Cr1Mo steel evaporator and austenitic superheater sections.

3. Both the high and low level oxygen water chemistry regimes have been shown to be successful in preventing erosion-corrosion damage (ref. 2-5), but for the combined regime adopted in the UK, which uses low oxygen levels, it is important to define the limits of its applicability, particularly since it involves dosing excess hydrazine ultimately to remove the oxygen which provides protection. Work has therefore been carried out at CERL to establish the oxygen concentrations required to inhibit erosion-corrosion under a variety of experimental conditions and in particular as a function of the metal loss rate and hydrodynamic conditions. In addition, it has sought to establish the influence of hydrazine on the process and the ability of oxygen to inhibit erosion-corrosion in the presence of excess hydrazine, particularly as a function of temperature.

4. The work has also made it possible to establish the relationship between the high and low oxygen dosing regimes, with respect to erosion-corrosion damage, and to explain why the incidence of damage can be rather variable in plant operating under nominally deoxygenated AVT water chemistry, where feedwater oxygen levels are <10 $\mu g\ kg^{-1}$ and hydrazine is dosed as a scavenger for residual oxygen.

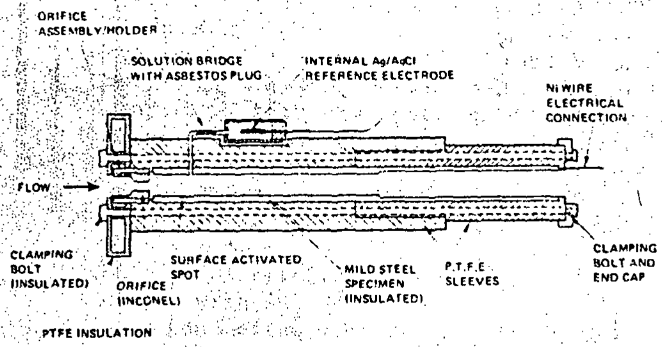


Fig. 1 Orifice assembly test specimen with electrochemical monitoring

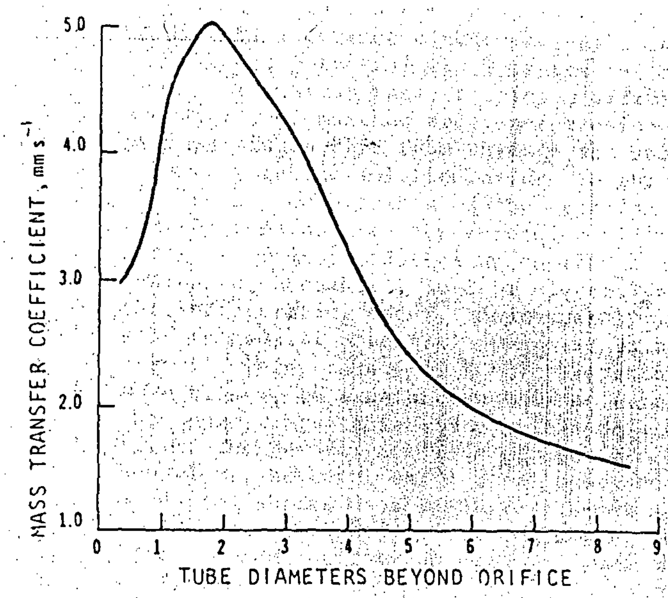


Fig. 2 Typical mass transfer coefficient variation downstream of an orifice

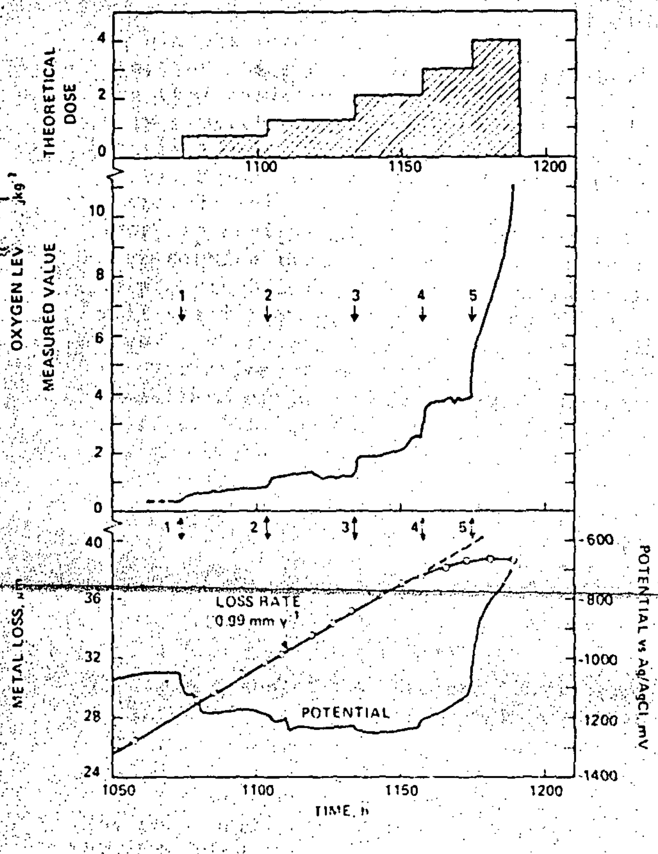


Fig. 3 Influence of oxygen on erosion-corrosion and specimen potential at 150°C
1, Start O_2 dose
2-5, O_2 dose increased

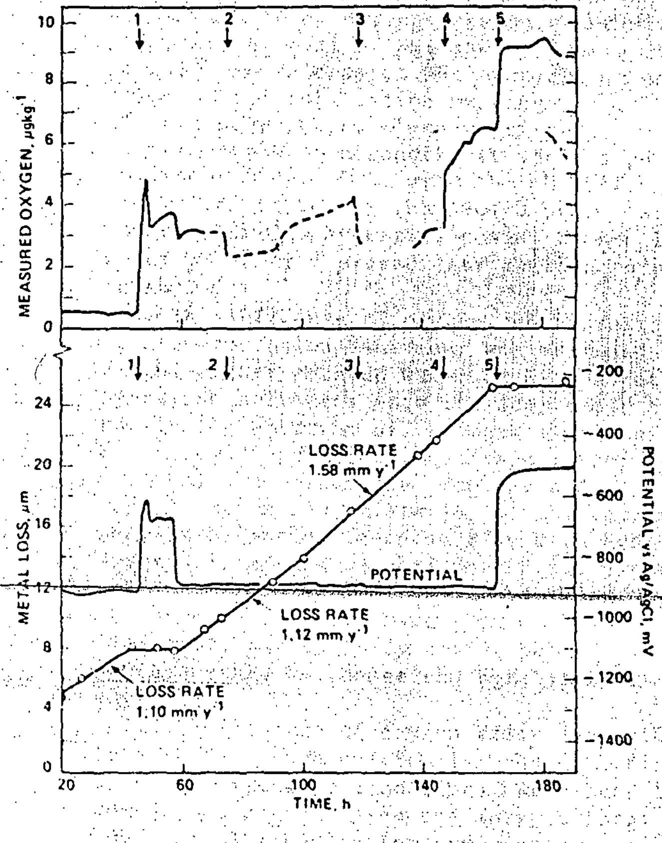


Fig. 4 Influence of oxygen on erosion-corrosion and specimen potential at 150°C
1, Start O_2 dose. 2, O_2 dose switched to 2nd flow channel. 3, O_2 dose stopped. 4, Start 2nd O_2 dose. 5, Dose increased.

EXPERIMENTAL STUDIES

5. The erosion-corrosion studies described here were carried out using the CERL high velocity isothermal water loop. Full details of the test loop have been given elsewhere (ref. 1, 8). It incorporates four main specimen flow channels, two in the main loop, and two in a secondary polishing loop. The rig is largely constructed from Type 316 stainless steel and designed to operate up to 350°C and 21.78 MN m^{-2} pressure. The experimental programme has shown it to be capable of operating for long periods with very precise control of both physical and chemical conditions. The control limits are indicated below:

- Temperature, ±1°C
- Flow to test specimens, ±1% up to 1031 kg h^{-1}
- pH of circulating water*, <±0.05 pH unit with NH_3 dosing
- Conductivity of water after cation exchange, <0.2 μS cm^{-1}
- Dissolved active silica in recirculating water, <6 μg kg^{-1}
- Dissolved Fe in circulating water*, <10 μg kg^{-1}

*Value depends on specific conditions of test, typically much lower values of dissolved Fe are obtained.

6. For the present studies, test specimens of the type shown in Fig. 1 were used. These are very similar in principle to those used previously in our experimental programme (ref. 1, 2), but have been modified to allow electrochemical monitoring of the specimen. The basic specimen design employs an inlet orifice, made from erosion resistant material (Inconel 600), to produce highly turbulent conditions in the mild steel tubing downstream, which in turn gives rise to the erosion-corrosion damage. The variation of mass transfer coefficient downstream of an orifice is well characterised (ref. 9, 10), as shown in Fig. 2, with the maximum value being defined by the relationship:

$$Sh_{max} = 0.276\ Re_N^{0.67}\ Sc^{0.33} \qquad \ldots (1)$$

where Sh_{max} = maximum Sherwood number observed downstream of orifice
Re_N = orifice Reynolds number
Sc = Schmidt number

The mass transfer coefficient, K. is expressed in terms of the Sherwood number by the relationship $Sh = KD/\mathcal{D}$, where D = duct diameter and $\mathcal{D}$ = diffusion coefficient.

7. The erosion-corrosion loss in the region of the post orifice maximum was monitored in-situ by observing the activity loss from specimens which had been surface activated with ^{56}Co, as indicated in Fig. 1. Full details of the technique used have been given elsewhere (ref. 11). The loss sensitivity in the present studies was better than ±0.15 μm, allowing very accurate determination of specimen response to changes in the water chemistry and in particular to the oxygen dose level.

potentials with respect to an internal Ag/AgCl/ 0.01 M KCl reference electrode. As shown in Fig. 1, the potential was measured in the region of maximum mass transfer coefficient and, therefore, of maximum erosion-corrosion loss, by inserting a PTFE tube through the specimen wall to form the solution bridge to the specimen. Measurements of the chloride concentration remaining in the reference electrode after experiments lasting up to 1200 hours indicated substantial loss of electrolyte to the recirculating water. Consequently, the electrochemical potentials measured do not strictly refer to a 0.01 M KCl reference, but more closely to a saturated AgCl solution at the appropriate temperature. This does not affect the general analysis of specimen behaviour, however, since it is based on large potential shifts over relatively short periods of time (a few hours), when the electrode would have reached equilibrium with the environmental conditions.

CONDITIONS AND MONITORING OF WATER CHEMISTRY

9. The experiments described here were carried out in deoxygenated AVT feedwater, to which controlled levels of oxygen and hydrazine were then added. The pH of the recirculating water was controlled with NH_3. This was effected both by dosing make-up water with the appropriate level of NH_3 and by controlled removal and release of NH_3 by hydrogen and ammonium ion form cation exchange resin beds in the secondary water clean-up circuit. Experiments were conducted at various pHs in the range 8.0 to 9.3, with the pH typically controlled to better than ±0.05 pH units. However, during hydrazine dosing to the loop water pH control proved less satisfactory (see below).

10. The influence of oxygen and hydrazine on erosion-corrosion behaviour was examined by dosing either aerated water or N_2 sparged hydrazine solutions into the loop water approximately 1 m upstream of the test specimens. In the case of hydrazine, the reagent rapidly recirculated around the loop and a stable concentration was maintained at the test specimens by balancing the dose rate with hydrazine decomposition and removal on the ion exchange columns. Unfortunately this displaced NH_3 from the ammoniated resin making pH control more difficult, particularly during periods when it was necessary to change the N_2H_4 level in the water.

11. In the case of oxygen dosing into the loop, when it had previously been operating under deoxygenated (reducing) conditions for some time, magnetite on the loop surfaces had a substantial capacity for removing oxygen in the recirculating water. As a result of this O_2 'gettering', it was usually necessary to run at a constant O_2 dose level for some time before steady oxygen levels were established at the inlet to the test specimens. This also ensured equilibration and negligible O_2 loss in the sample lines, which were located approximately 15 cm upstream of the specimens. Valves in the

mixing of the dose and recirculating water. After prolonged periods of O_2 dosing to the loop water, it was found to recirculate around the loop and the O_2 level at the test specimens rose cumulatively, as indicated in Fig. 3.

12. Because of the difficulties of sampling and measuring O_2 at the very low levels involved in the present work, great care was taken to ensure the accuracy of such measurements by multiple method determination at various points in the loop circuit. Samples were drawn continuously from a sampling point at the inlet to the test specimen in the flow channel being dosed and from an equivalent point in the parallel flow channel ahead of a second test specimen. This provided a check on oxygen recirculation around the loop and allowed 'differential' experiments to be conducted where erosion-corrosion was maintained in the undosed flow channel, but inhibited in the dosed one. The O_2 concentration in the recirculating water was also monitored downstream of the ion exchange column in the polishing loop by batch analysis and on a continuous basis in some experiments.

13. The oxygen levels quoted in the present paper were measured using an Orbisphere model 2713 membrane polarographic O_2 monitor. Measurements were normally made with a total sample flow rate of around 80 ml min^{-1} and a flow of 9 ml min^{-1} through the monitor itself. With flow rates of this order and strenuous efforts to ensure minimum O_2 ingress on the low pressure side of the sampling system, measured O_2 levels in He sparged 'blank' water were typically in the range 0.2 to 0.3 $\mu g\ kg^{-1}$. Similar values were obtained from loop water after operation under deoxygenated conditions for a few days. With lower sample flow rates slightly higher oxygen levels were observed. Oxygen measurements obtained using the continuous autoanalyser version of the leuco-methylene blue method (ref. 12) were in good agreement with those obtained using the Orbisphere instrument and indicated the absolute values to be accurate to about $\pm 0.5\ \mu g\ kg^{-1}$ in the 0 to 10 $\mu g\ kg^{-1}$ range.

14. As noted earlier, the absolute O_2 levels measured may be unrepresentative of that reaching the specimen if significant oxygen consumption occurs within the sample lines. As a rule, therefore, several hours equilibration were allowed at any given oxygen dose level to ensure that the O_2 level determined was indeed representative of that reaching the specimen. Typically, however, when O_2 dose levels were changed, the majority of the increment was seen within an hour or so. In those cases where O_2 recirculation around the loop could be demonstrated not to have occurred, the oxygen levels were cross checked by comparison with the theoretical values expected from the O_2 dose rate. Fig. 3 shows a good example of such a comparison for O_2 dosing at 115°C. Only at the end of the dosing period is O_2 recirculation evident and prior to this agreement between measured and theoretical O_2 levels is good.

15. At temperatures of 180°C and above, increased O_2 consumption by loop surfaces and sample lines made reliable oxygen measurements more difficult. Under these circumstances, it was necessary to use the theoretical oxygen level derived from the dose rate to give an upper limit for the oxygen level at the test specimen. While this allowed demonstration of effects due to low levels of O_2, equivalent to those observed at lower temperature, it precluded accurate quantitative assessment. Similarly, it was not possible to measure oxygen concentrations in the presence of hydrazine at these temperatures and data again had to be related to the theoretical O_2 dose. At 150°C and below, however, the hydrazine-oxygen reaction was sufficiently slow to allow measurement of O_2 in the presence of hydrazine. In both cases it was possible to demonstrate clearly the effects of oxygen in the presence of excess hydrazine.

16. Hydrazine in loop water was monitored continuously using the p-dimethylamino-benzaldehyde hydrazone auto-analyser method (Technicon Auto Analyser Industrial Method No. 147-71WM, 1973). Hydrogen in the loop water was determined by gas chromatography of the dissolved gases, which had been stripped from the sample water by diffusion through a silicone rubber membrane into a helium carrier gas (ref. 13). It was not possible to control hydrogen in the loop water and its concentration increased progressively with temperature as a result of the increased corrosion of steel surfaces in the loop (from around 15 $\mu g\ kg^{-1}$ at 115°C to 90 $\mu g\ kg^{-1}$ at 210°C).

RESULTS AND DISCUSSION

Influence of Oxygen on Erosion-Corrosion

17. Fig. 3 shows the influence of a progressively increasing O_2 dose on a specimen undergoing rapid erosion-corrosion loss (0.99 mm $year^{-1}$) at 115°C and pH 9.1. The O_2 level was progressively increased to 2.1 $\mu g\ kg^{-1}$ without any noticeable effect on the erosion-corrosion rate over a period of about 70 hours. However, the specimen showed a progressive shift to more negative potentials with increasing oxygen level over this range. This effect has been noted previously at low temperature (ref. 2), but its origin is unclear at present. Increasing the O_2 concentration to 3.8 $\mu g\ kg^{-1}$ can be seen to have caused a reduction in the erosion-corrosion rate over a period of 24 hours and shifted the specimen potential more positive again. In view of the continuing positive drift of the specimen potential at the end of this period, it is possible that further exposure at this oxygen concentration would have stopped the erosion-corrosion loss eventually. However, increasing the concentration to no more than 6.2 $\mu g\ kg^{-1}$ caused the potential to shift sharply more positive and stopped further erosion-corrosion loss. Oxygen recirculation around the loop prevented more precise control of the O_2 concentration and hence more accurate definition of the concentration required to inhibit attack.

18. Fig. 4 shows similar data for O_2 inhibition of erosion-corrosion at 150°C and at a rather lower pH, around 7.8. The low pH adopted in this case was to ensure high erosion-corrosion rates at this temperature. The initial oxygen

dose starting after 45 hours (4.9 $\mu g\ kg^{-1}$) immediately caused the ongoing erosion-corrosion loss of 1.10 mm $year^{-1}$ to be inhibited. Reduction of the oxygen concentration to around 3.5 $\mu g\ kg^{-1}$ continued to inhibit the process and to maintain the much more positive specimen potential. However, reducing the oxygen concentration to 3.2 $\mu g\ kg^{-1}$ allowed erosion-corrosion to reinitiate rapidly, at a rate similar to that seen previously. At the time, the specimen potential was seen to shift sharply negative to a value similar to that observed prior to O_2 dosing. Subsequently, the erosion-corrosion rate increased to 1.58 mm $year^{-1}$ and continued at this value during oxygen dosing until the O_2 concentration was raised above 6.5 $\mu g\ kg^{-1}$. Again, the positive shift in specimen potential and cessation of erosion-corrosion loss was almost immediate on raising the concentration above the threshold.

19. Experiments of the type described above have been repeated many times at these two temperatures with essentially the same result, except that the O_2 threshold for inhibition of erosion-corrosion varied with the loss rate and mass transfer coefficient to the specimen surface. At higher temperatures, up to 250°C, the results were similar, but obtaining an oxygen threshold was more difficult due to the difficulties in oxygen determination and the low erosion-corrosion rates encountered.

20. It is important to note that the oxygen dosing experiments at 115°C and 150°C were carried out with 10 to 20 $\mu g\ kg^{-1}$ dissolved hydrogen in the loop water. This represents a large excess of H_2 over the O_2 concentrations used to inhibit erosion-corrosion, typically an order of magnitude greater than that required to combine with the oxygen via the formal reaction:

$$H_2 + \tfrac{1}{2}O_2 \rightarrow H_2O \qquad \ldots (2)$$

Nevertheless, it was still the oxygen present which controlled the specimen electrochemical potential and erosion-corrosion behaviour. This was also found to apply at temperatures up to 250°C and with even larger excesses of hydrogen (up to 2 orders of magnitude). It should also be noted that these H_2 levels are of course higher than those normally encountered in boiler feedsystems.

21. The rapid shift in electrochemical potential to much more positive potentials and the inhibition of the erosion-corrosion process above a threshold O_2 concentration is consistent with a switch in the cathodic reaction of the corrosion process from hydrogen evolution to oxygen reduction. That is,

$$\text{From} \quad 2H^+ + 2e \rightarrow H_2 \qquad \ldots (3)$$

$$\text{To} \quad \tfrac{1}{2}O_2 + H_2O + 2e \rightarrow 2OH^- \qquad \ldots (4)$$

In the case of active erosion-corrosion, the cathodic hydrogen evolution reaction (3) is balanced by an equal and opposite anodic one leading to the dissolution of iron as Fe^{2+} species. The latter is generally agreed to occur via the reductive dissolution of the magnetite corrosion film formed on the metal surface (ref. 2).

22. The specimen electrochemical behaviour is also consistent with the rate of oxygen reduction being controlled by the rate of oxygen mass transfer to the specimen surface. A reasonable initial approach to assessing the oxygen concentration necessary to inhibit any given erosion-corrosion rate is, therefore, to compare the rate under fully deoxygenated conditions with the rate of oxygen mass transfer to the specimen surface required to inhibit the process. This is, to equate the anodic reaction rate with the equivalent cathodic reaction (4), which would have been required to balance it if the erosion-corrosion loss had continued unaffected. i.e.

$$K_{O_2}[O_2]\rho_w \equiv \text{Erosion-Corrosion Rate} \quad \ldots (5)$$

where K_{O_2} = local oxygen mass transfer coefficient

$[O_2]$ = concentration of oxygen in solution required to inhibit the erosion-corrosion loss

ρ_w = density of water.

If the relationship given in equation (5) holds, then plots of the oxygen threshold versus (Erosion-Corrosion Rate)/$\rho_w K_{O_2}$ should give a straight line of slope 0.285, defined by the equivalent weights of Fe and O_2 in the corrosion process.

23. Fig. 5 and 6 show plots for the influence of oxygen on erosion-corrosion rate derived from our data at 115°C and 150°C, respectively. The mass transfer coefficients for oxygen were calculated using the expression given in equation (1), taking the diffusion coefficients for oxygen (K_{O_2}) as $8.8 \times 10^{-9}\ m^2\ s^{-1}$ and $1.27 \times 10^{-8}\ m^2 s^{-1}$ at 115° and 150°C, respectively (ref. 15). Other aqueous constants were taken from standard steam tables. Since the threshold itself is not as readily defined as the alternatives where erosion-corrosion continues unaffected or is completely inhibited, Figs. 5 and 6 are constructed on the latter basis, the threshold being the boundary line between the two zones. As expected there is a band of uncertainty associated with this, defined by the half closed symbols and the dashed lines.

24. At both 115° and 150°C there is clearly an oxygen concentration threshold below which erosion-corrosion is unaffected and above which the process is inhibited, which can be defined in terms of the pre-existing erosion-corrosion rate and the rate of oxygen mass transfer to the surface. However, the slope of the threshold line is lower than that predicted by equation (5), by a factor of 4 for the correlation at 150°C, which represents the better data set. It is important to point out, however, that the experimentally determined erosion-corrosion rate is equated to a theoretically derived rate of oxygen mass transfer. For many corrosion processes, such close agreement between experiment and theory would be considered sufficient to confirm the theoretical analysis. However, examination of the possible errors involved in the estimation of oxygen mass transfer and erosion-corrosion rate, indicates that the deviation of the slope of the threshold lines from the predicted value of 0.285 is real. Thus rather less oxygen is

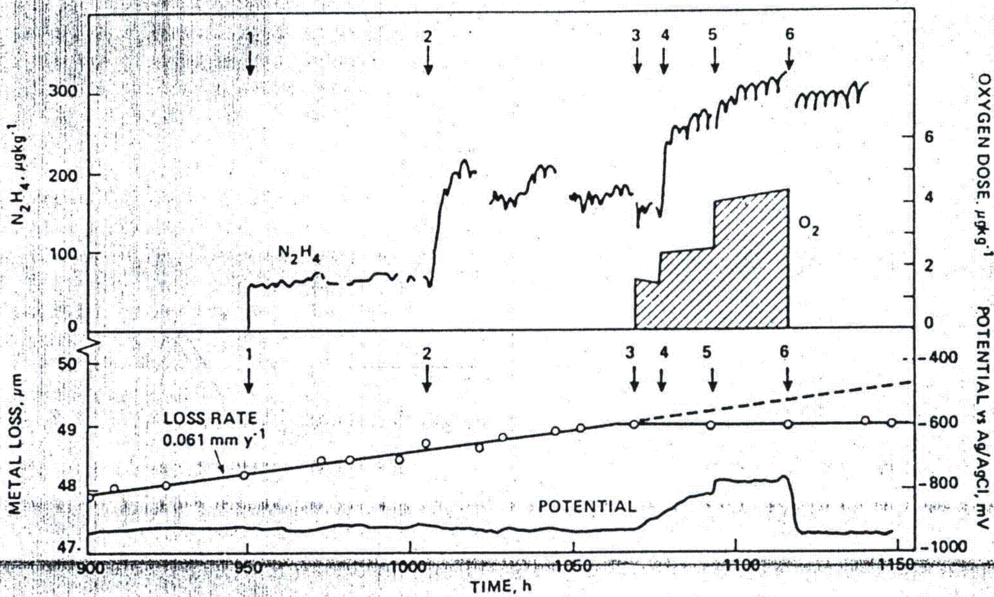
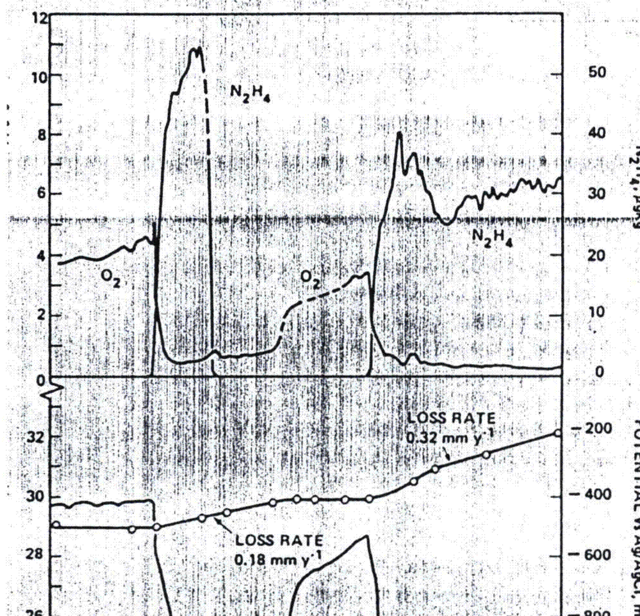


Fig. 8 Influence of oxygen in the presence of hydrazine on erosion-corrosion and specimen potential at 210°C.
1, Start N_2H_4 dose. 2, N_2H_4 dose increased. 3, Start O_2/N_2H_4 dose. 4 & 5, O_2/N_2H_4 dose increased. 6, O_2 dose stopped.



3. 9 Effect of hydrazine on erosion-corrosion and specimen potential due to removal of oxygen, at 150°C

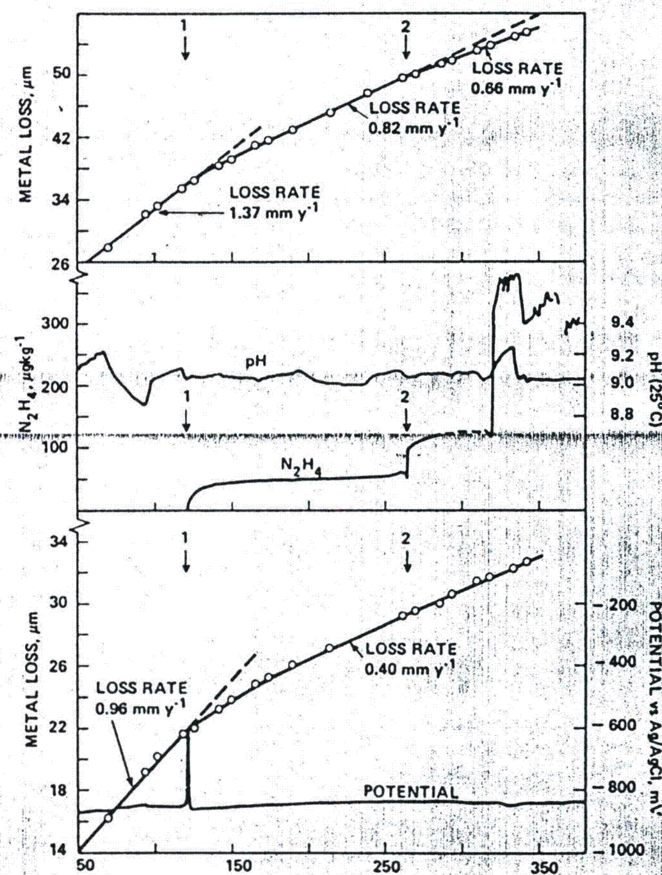


Fig. 10 Effect of hydrazine on erosion-corrosion and specimen potential in absence of oxygen at 180°C
1, Start N_2H_4 dose. 2, Dose increased.

:equired to inhibit erosion-corrosion than vould be predicted by equating the loss rate to :he rate of oxygen mass transfer to the surface. The latter does appear to represent an upper limit to the amount required for inhibition though.

?5. Whether the O_2 threshold for inhibition ·eases with increasing temperature as indicated by Figs. 5 and 6 is uncertain. The lata at 115° and 150°C can be treated as a single set, but there is then greater scatter of the threshold values. It may at first seem surprising that the O_2 thresholds are less than :hose predicted by the mass transfer analysis, ›ut it appears to be consistent with the mechanism proposed for the erosion-corrosion process by :he present authors (ref. 1, 2). In effect the process is self accelerating, due to the need :o evolve hydrogen at progressively more negative potentials in order to match the modic dissolution rate. This, in turn, raises the solubility of the magnetite corro- :ion film, allowing even higher mass transfer imited dissolution rates. When oxygen reduc- :ion starts to compete with hydrogen evolution :s the cathodic reaction, the potential will tart to shift in the positive direction, educing the solubility of the magnetite film. his, in turn, will lead to further reductions n the mass transfer limited dissolution rocess and, as the oxygen level is increased urther, to a very sharply reducing erosion- orrosion loss rate. Our observation of a elatively narrow range of oxygen concentra- ions over which the loss rates are reduced, ut which do not completely inhibit the ~ocess, appears to match this view of the .bition mechanism. Further analysis of this spect of erosion-corrosion behaviour is under nvestigation.

26. As drawn, Figs. 5 and 6 show a positive ntercept of 1.5 µg kg^{-1} for the O_2 threshold t zero erosion-corrosion rate. Equation (5) redicts that the intercept should be zero. art of this offset may be accounted for by the ositive 'blank' oxygens measured, typically .2 to 0.3 µg kg^{-1}, and by the difficulties of :curate measurements at such very low oxygen oncentrations. However, the data do not :eclude the possibility that the threshold .ses more rapidly at these very low O_2 oncentrations, with a rather lower intercept ıan that indicated. This would be consistent .th the view that for very low erosion- orrosion rates, where the self accelerating :chanism of the process is much less portant, the threshold approximates more .osely to that given by equation (5).

fluence of Oxygen in the Presence of Hydrazine

7. As noted earlier, oxygen is effective in hibiting erosion-corrosion in the presence of cess hydrogen. Fig. 7 shows the influence of ygen in the presence of a vast excess of drazine at 180°C. It was not possible to asure the oxygen level reaching the specimen, ? to the reaction with hydrazine in the rig tween dosing and sampling point) and down the sample line. Consequently, the Fig. 7. This represents the upper limit of O_2 which could have been present at the specimen, but even these modest levels (<7 µg kg^{-1}) were sufficient to inhibit an ongoing erosion-corrosion rate of 0.79 mm $year^{-1}$ in the presence of around 180 µg kg^{-1} N_2H_4. Fig. 8 shows that oxygen is equally effective at 210°C for inhibiting erosion-corrosion in the presence of around 300 µg kg^{-1} N_2H_4, although the loss rates were much lower at this temperature. In both cases there was also a large excess of hydrogen present over the oxygen concentration (H_2 ∿ 90 µg kg^{-1} at 210°C). It is clear, therefore, that low levels of oxygen control the incidence of erosion-corrosion even in the presence of huge excesses of the two common reducing agents likely to be present in boiler feedwater, namely H_2 and N_2H_4, and our data shows this to be the case up to 250°C.

28. Since oxygen is the potential controlling species with carbon steel up to 250°C, it is likely that other corrosion or oxide deposition processes are influenced by very low levels of oxygen in the feedwater, even though excess H_2 or N_2H_4 may be present. Of course, these reducing agents will remove O_2 from the feed-water given sufficient time, but the reaction kinetics are sufficiently slow, particularly at the lower temperature end of our investigations, that O_2 can penetrate many metres through the feed system and into the boiler. It is, therefore, clear why haematite is frequently observed in the low temperature (<250°C) parts of power plant boiler and feed systems, even with nominally deoxygenated feedwater and added hydrazine. The data of Ribon and Berge (ref. 15) provide a good example of such behaviour in a conventional boiler operating with a deoxygenated AVT feedwater chemistry with addition of hydrazine. Up to 265°C, haematite was the major oxide phase observed in corrosion product samples taken from the boiler system. Above this temperature magnetite predominated. It is also clear why zones of active erosion-corrosion damage, where the metal surface is covered with magnetite, can be surrounded by adjacent ones covered by haematite. While oxygen levels are insufficient to inhibit damage in the highly turbulent regions, they are sufficient to shift the surface potential to more positive values in areas of lower mass transfer and, hence, to lead to the formation of haematite. Similarly, some boiler feed systems operating with nominally 'deoxygenated' feedwater may suffer serious erosion-ocorrosion problems, whilst others which are apparently similar, but in reality have slightly higher feedwater oxygens, show none.

29. When reaction times are long enough, Fig. 9 shows that hydrazine will efficiently remove O_2 at low levels (<5 µg kg^{-1}) and allow erosion-corrosion to reinitiate rapidly.

Direct Influence of Hydrazine on Erosion-Corrosion

30. Fig. 10 shows the influence of hydrazine on erosion-ocorrosion in the absence of oxygen (<0.5 µg kg^{-1}) at 180°C and essentially

15. RIBON C. and BERGE J.Ph. Magnetite deposits in boilers from iron in solution. Proc. Am. Power Conf., 32, 721, 1970

16. COBBLE J.W. and TURNER P.J. Additives for pH control in PWR secondary water. EPRI Report NP-4209

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:

Alex S. Karlin, Chairman
Dr. Richard E. Wardwell
Dr. William H. Reed

In the Matter of ENTERGY NUCLEAR VERMONT YANKEE, LLC, and ENTERGY NUCLEAR OPERATIONS, INC. (Vermont Yankee Nuclear Power Station)	Docket No. 50-271-LR ASLBP No. 06-849-03-LR June 20, 2006

PRE-FILED REBUTTAL TESTIMONY OF DR. RUDOLF HAUSLER REGARDING NEC CONTENTION 4

Q1. Please state your name.

A1. My name is Rudolf Hausler.

Q2. Have you previously provided testimony in this proceeding?

A2. Yes, I provided direct testimony in support of New England Coalition, Inc.'s (NEC) Initial Statement of Position, filed April 28, 2008.

Q3. Have you reviewed the initial statements of position, direct testimony and exhibits filed by Entergy and the NRC Staff concerning NEC's Contention 4?

A3. Yes. I have reviewed the section of Entergy's Initial Statement of Position on New England Coalition Contentions (May 13, 2008) that concerns NEC's Contention 4 and all Exhibits thereto, and the Joint Declaration of Jeffrey S. Horowitz and James C. Fitzpatrick on NEC Contention 4 – Flow-Accelerated Corrosion (May 12, 2008). I have also reviewed the section of the NRC Staff Initial Statement of Position on NEC Contentions 2A, 2B, 3, and 4 that concerns NEC's Contention 4 and all exhibits thereto, and the Affidavit of Kaihwa R. Hsu and Jonathan G. Rowley Concerning NEC Contention 4 (Flow-Accelerated Corrosion) (May 13, 2008).

Q5. Did you prepare a report of your evaluation of the Entergy and NRC Staff Initial Statements of Position and direct testimony on NEC's Contention 4?

A5. Yes, I did. This report is filed with this rebuttal testimony as Exhibit NEC-RH_05.

Q6. Please briefly summarize your conclusions as stated in your report filed with this testimony as Exhibit NEC-RH_05, and the bases for your conclusions.

A6. Entergy witness Dr. Horowitz has testified that it is not necessary to recalibrate or "benchmark" the Checworks model with plant inspection data following a twenty percent power uprate. Joint Declaration of Jeffrey S. Horowitz and James C. Fitzpatrick on NEC Contention 4 – Flow-Accelerated Corrosion at A33, 34. Rather, Dr. Horowitz contends that the only update to the Checworks model that is necessary following a twenty percent power uprate is the input of new values for flow rate and temperature into the model. Horowitz at A33, 34. Dr. Horowitz bases these assertions on his view that "[flow-accelerated corrosion (FAC)] wear rates vary roughly with velocity and do not increase with velocity in [a] non-linear (exponential) manner. . . .", Horowitz at A49, and his belief that the Checworks model can accurately predict any variations in FAC rates related to geometric features. Dr. Horowitz contends that the Checworks model accounts for any localized variations in FAC associated with geometric features through the use of " 'geometric factors' to relate the maximum degradation occurring in a component, such as an elbow, to the degradation predicted to occur in a straight pipe." Horowitz at A47, 48.

As explained in detail in my report, Exhibit NEC-RH_05, I agree that the rate of FAC generally varies almost linearly with fluid velocity; however, this linear relationship transitions to an exponential one as the local turbulence becomes such that erosional features become manifest. Whether such transition actually occurs when flow velocity increases following a power uprate must be determined experimentally. I do not agree that the Checworks model, or any model, can fully account for variations in the rate of FAC due to geometric features and discontinuities. Some things cannot be specified. For example, the internal residual weld bead from the root pass may be 1/8 inch high in one case, and ¼ inch high in another case. The upstream and downstream turbulence surrounding the weld bead will be more severe in the latter case, and a power uprate may disproportionately affect the flow over the larger bead.

Dr. Horowitz defines FAC as corrosion in proportion to the flow rate, and excludes from the definition of FAC the more severe forms of localized corrosion – erosion-corrosion, impingement and cavitation. *See,* Horowitz at A46. This definition of FAC is entirely arbitrary. Erosion-corrosion, impingement and cavitation are extensions of FAC as the local flow intensity due to turbulence increases. The transition from one to the others is continuous and difficult to identify. If Checworks is unable to predict these more severe forms of localized corrosion related to high flow rates, which can particularly occur after a power uprate, then this is a serious shortcoming of the model and its application.

The accuracy of Checworks has been said to be within +/- 50%. This statement is based on an erroneous interpretation of the graphic representation of predicted vs. measured wear. Actually, the accuracy is within a factor of 2 – the measured wear rates range from twice the prediction to half the prediction. A factor-of-two difference between measured and predicted corrosion [or corrosion rate] can be quite significant with respect to selecting a particular item (line) for inspection during a refueling outage. Indeed, the "EPRI Checworks Wear Rate

Analysis Results for Cycle 22B," Exhibit E-4-29, shows that the time predicted to reach the critical minimum wall thickness in a majority of cases is many years *negative*. This means that the item should have failed a long time ago. The remaining time to failure might just as readily be grossly overestimated. But one will never know unless the proper inspections are performed and the model is recalibrated.

Q7. Does this conclude your rebuttal testimony regarding NEC's Contention 4 at this time?

A7. Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Rudolf H. Hausler

Rudolf Hausler, PhD

At Kaufman, Texas, this 28 day of May, 2008 personally appeared Rudolf Hausler, and having subscribed his name acknowledges his signature to be his free act and deed.

Before me:

Jennifer Juliana Perez

Notary Public

My Commission Expires August 22, 2011

JENNIFER JULIANA PEREZ
Notary Public
STATE OF TEXAS
My Comm. Exp. August 22, 2011

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Flow Assisted Corrosion (FAC) and Flow Induced Localized Corrosion: Comparison and Discussion

Summary

- The computer model Checworks, used to manage aging of hot high pressure water and steam carbon steel lines was designed for Flow Assisted Corrosion (FAC) phenomena. Erosion Corrosion, Impingement and Cavitation are expressly excluded as unrelated to FAC. It is shown that the latter three corrosion phenomena are extensions of FAC as the local flow intensity due to turbulence increases. The transition from one to the others is continuous and difficult to identify. FAC therefore is only one manifestation of Flow Induced Localized Corrosion (FILC).

- The localized corrosion rate under the umbrella of FAC varies, per definition, almost linearly with fluid velocity; however, this linear relationship transitions into an exponential one as the local turbulence becomes such that erosional features become manifest. Whether such transition actually occurs following a power upgrade (PU) must be determined experimentally. It cannot be estimated from within Checworks.

- It has been stated that "the algorithms used to predict the FAC wear rate are based on extensive laboratory and plant data. This assures that the FAC wear rates predicted by Checworks are accurate." This accuracy is said to be within +/- 50%. However, this statement is based on an erroneous interpretation of the graphic representation of predicted vs. measured wear. Actually, the accuracy is within a factor 2. The measured wear ranges from twice the predicted to half the prediction.

- Partial review of the result from the pipe inspections using Checworks in 2003 and 2006 shows significant unexplained discrepancies.

I. Introduction

The direct testimony by Dr. Jeffrey S. Horowitz and Dr. James C. Fitzpatrick[1)] with regards to NEC Contention 4 – Flow Accelerated Corrosion has raised a number of questions, which are being discussed below:

[1)] Joint Declaration of Jeffrey S. Horowitz and James C. Fitzpatrick on NEC Contention 4 – Flow-Accelerated Corrosion, May 12, 2008.

- Is the model called Checworks based on sufficiently broad scientific understanding of all pertinent corrosion phenomena?
- Is the model called Checworks broad enough to capture all flow-assisted corrosion phenomena, or more broadly Flow Induced Localized Corrosion (FILC) in general?
- Is the model called Checworks suitable to manage aging of the hot water and steam piping system at the Vermont Yankee Power Plant?
- Is the predictive power of the model called Checworks within a probability range to prevent unforeseen catastrophic failure?
- Does the model called Checworks require extensive recalibration?

In order to tackle some of these questions I shall discuss some of the pertinent background and try to unravel the conundrum of language, which has, it seems to me, caused some misunderstandings if not outright confusion.

II. Background

1. The Chemical Nature of the Passive Steel Surface

It is well established that under certain conditions corrosion occurs in carbon steel hot water pipes in nuclear (and fossil) power generation plants. The chemical nature of this phenomenon is straightforward: iron reacts with water to form iron ions and hydrogen. The reaction is thermodynamically favored.[2)]

However, the physicochemical nature of the processes occurring in conjunction with the oxidation of iron, is infinitely more complex and, although investigated in great detail,[3)] generally not easily understood.

Ferrous (Fe^{+2}) or ferric (Fe^{+3}) ions are not stable by themselves at the prevailing temperatures (~300 ^{O}F) at a neutral or slightly alkaline pH. Either ion will react with water and form hydroxides, oxy-hydroxides, or oxides. The reaction occurs on the surface of the metal where an oxide layer forms, which slows the corrosion reaction or prevents it from occurring altogether. The phenomenon is called passivation and makes it possible for iron, steels, or stainless steels to be used as industrial materials to begin with. At the temperatures in question the passive layer is a thin crystalline "coating" of magnetite on the surface of the steel, Fe_3O_4, a mineral also found in nature. Fe_3O_4 is a combination compound formed from FeO and Fe_2O_3, generically called a Spinell. Because of the nature of the Spinell-type oxide combining in essence a two-valent iron with a three-valent iron ion, magnetite is electrically conductive and

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[2)] NEC-RH_03: R. H. Hausler, Discussion of the Empirical Modeling of Flow-Induced Localized Corrosion of Steel under High Shear Stress, April 25, 2008, pg 3.

[3)] See ACS Symposium Series Vol. 89 (1982), Editors: G.R. Brubaker, and P.B. Phipps, Chapters by Maurice Cohen, Vlasta Brusic, and J.E. Draly.

forms a contiguous thin, non-porous albeit crystalline layer on the surface of the metal.

2. The Physical Nature of the Passive Magnetite Layer

Steel in the passive state will not corrode or only at extremely slow rates (10^{-3} to 10^{-2} mpy). The question then is: What makes iron in the passive state corrode? Why do hot water or steam pipes in nuclear power generating units fail due to corrosion? Why are the failures predominantly local while the rest of the structure remains intact and passive for many years?

Any phenomenon that can destroy the protectiveness of the passive layer or assist in removing the passive layer will cause the steel to corrode at rates 10^3 to 10^4 times faster, i.e. at corrosion rates observed in the power plants.

What are these phenomena? In order to better understand this one needs to understand that magnetite is an electronic conductor. It can pass electrons from the metal side to the water-side where they can be consumed by an electrochemical reaction. Magnetite, however, cannot conduct ions. Neither iron ions nor oxide ions are mobile in magnetite.[4)] The phenomena that destroy the protectiveness of the passive layer are essentially chemical in nature, but may, however, be assisted by physical effects. For instance, chlorides in the water will convert magnetite to iron-oxy-hydroxy-chlorides, (various modifications thereof), which are much more soluble than magnetite and also can conduct ions. The result is that the passivity has been lost.[5)] This is the mechanism that prevails in the crevices of the steam generators of PWR's and is the primary cause of denting.

Magnetite has a finite, albeit very small, solubility in hot water. The dissolution of minerals in water is aided by agitation, i.e. forced convection. Salt (sodium chloride), e.g., will not dissolve in stagnant water, but will readily go into solution when the solution is agitated. The dissolution process will stop when the solution is saturated with the salt. This is in essence how the corrosion process of steel in hot water has to be visualized. I have tried to sketch the physical reality as simplified as reasonably permissible in Figure 1.[6)] The water layer close to the magnetite surface is saturated with iron oxide in equilibrium with the magnetite layer. The iron concentration in the bulk water phase is practically zero. Therefore a concentration gradient develops from

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[4)] Because of the physical nature of magnetite iron, it is also called a valve-metal (in analogy to aluminum). However, the magnetite layer is distinctly different from such corrosion product layers as iron sulfide or iron carbonate. Iron sulfide, for instance, is a p-type conductor based on iron ion vacancy mobility. This layer therefore can grow from the solution side, a process not possible with magnetite, because magnetite cannot conduct iron or oxide ions.

[5)] The phenomenon is well known in the nuclear industry since it is the primary cause of "denting" observed in stream generators of PWRs.

[6)] Note that this Figure and the mechanism derived therefrom essentially mirror Dr. Hopenfeld's explanations: NEC_JH_36 at pg 3 and Fig. 1.

the magnetite surface across the stagnant boundary layer. The solubility of iron (from magnetite) is very, very low. Hence, the mass transfer of iron ions across the stagnant water layer near the magnetite surface, which occurs by diffusion and is controlled by the concentration gradient, is very low as well. The thickness of the stagnant layer, which is infinite if there is no flow, is reduced as flow over the surface increases. Therefore, as the flow [rate] over the surface increases, the stagnant layer (also called the laminar boundary layer or the diffusion layer) is reduced in thickness, the diffusion rate increases, and hence the dissolution rate of the passive layer. The thickness of the passive layer (which is very small to begin with) becomes a steady state value when its formation rate (the corrosion rate) equals the removal rate (dissolution and mass transfer rate). The latter is controlled by the flow rate. **Therefore, this type of corrosion has been termed Flow Assisted Corrosion (FAC).** However, as we will see below, the fact that the creators of Checworks have decided that the main characteristic of FAC is its proportionality to the flow rate is entirely arbitrary.

3. The various forms of FAC

If the flow (laminar or turbulent[7)]) is strictly uniform over the entire surface area of interest then the entire area will corrode uniformly and wall thickness loss is uniform.

However, at the prevailing flow rates (24 ft/sec in many cases) the flow pattern is not uniform because of the non-uniformity of the cross sections of the flow channels. **In particular, where flow upsets are built into the system, such as orifice plates, flanges, etc., localized turbulences occur which are much more intensive than are normally described by general flow equations**. The engineering approach is to characterize the flow at such flow disturbances by means of differential pressure drop and an average shear stress occurring at the disturbance. However, the difficulty is that the localized shear stress within the turbulence cannot be captured in this manner and is in general orders of magnitude higher than the average numbers[8)] would indicate.

The different paradigms can perhaps be explained by means of Figure 2 (below). Any geometric feature in a flow channel (pipe for instance) that reduces or expands the [hydraulic]-diameter, or changes the direction of flow, creates a flow disturbance (including sensors inserted into the pipe for temperature, pressure or other parameters). This means that the flow regime, which in the straight sections of the pipe may be fully developed laminar or turbulent flow changes to one, that also incorporates local turbulences (eddies). This leads to locally enhanced shear stress and hence enhanced mass transfer and therefore locally increased corrosion.

Just as flow in a pipe can be characterized by the pressure gradient, flow upsets, such as are shown in Figure 1, can be characterized by an average pressure drop (and

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7) For definition of turbulence in the general sense see Figure 2 Ref. 2.

8) c.f. for instance Figures 4 and 5 of Ref. 2

hence an increased average shear stress. Engineering practice has done this for a large number of flow features (elbows, orifices, t's, etc.) of varying diameter for the purpose of being able to calculate the pressure drop along complex piping systems.

Checworks now uses these flow features (56 of them) to record and classify observed and measured corrosion rates in a data base along with a host of environmental parameters (pressure, temperature, water chemistry, etc), physical parameters (flow rates, metallurgical features, and many more), as well as boundary conditions such as minimum critical wall thickness etc. Once the database has been established, statistical routines, such as multiple linear correlation, can be applied in order to extract explicitly and quantitatively the dependence of corrosion rate within the parameter space. The resulting correlations can then be used to predict corrosion rates for individual situations, which can be characterized well enough to be accommodated in the database (one of the 56 features). Certain theoretical concepts are combined with the multiple correlation, in particular the notion that corrosion increases proportionately with velocity.[9)]

Therefore, there are two major principles imbedded in Checworks:

- Flow features have been standardized in traditional engineering fashion (an elbow is always an elbow, an orifice is always an orifice, etc.). However, for certain features that could not be done: a weld is not always a weld, and a flange is not always a flange (see discussion below).

- A linear (or near linear) relationship between flow rate and mass transfer, i.e. corrosion rate, has been built into Checworks. It is for this reason that Dr. Horowitz indicates that certain failures, which had been identified as being caused by erosion or impingement could not have been predicted by Checworks, but that this lack of prediction does not invalidate the predictive value of Checworks.

It has been shown theoretically that the shear stress governs the mass transfer. Accepting this one can readily understand that at locations of high shear stress the magnetite dissolution is high and therefore the corrosion rate is high as well. This has led to the notion of flow induced *localized* corrosion (FILC). Clearly the phenomenon is "flow assisted" but it is localized. By that one does not mean pitting; rather, one refers to areas of some extension, which corrode faster than the adjoining metal. Much has been made of the extent of the areas subject to FILC (or FAC) because the risk associated with the resulting failure will be governed by the extent of corrosion.[10)]

[9)] See Ref. 1 Horowitz at A 49.

[10)] Understandably, the damage from a half-inch to one-inch "pinhole" may be considerably limited versus the damage from a pipe that splits open the length of several feet.

If only a small area corrodes due to enhanced local turbulence a small pit and eventually a small hole may result with only minor consequences. If on the other hand FILC (FAC) occurs over a larger area, the pipe may split open (as has indeed happened) with potentially disastrous consequences.

One can now reasonably ask the question as to what happens if the flow intensity exceeds that which has been empirically correlated in Checworks. In other words, if a certain localized enhanced corrosion rate has been observed over a period of years in the past and all of a sudden the flow rate (and hence the flow intensity) is increased, (EPU, power upgrade), will the local corrosion rates simply increase proportionately in accordance with the established laws relating average shear stress to mass transfer, or will the local corrosion rates increase exponentially as has been suggested earlier? In the first instance Checworks would predict the new corrosion rate, in the second instance Checworks would have to be recalibrated, or even fundamentally modified to accommodate the new relationships. **This is the fundamental question that must be answered before Checworks can be accepted as the basic tool to manage aging of these pipes.**

Indeed additional phenomena related to high flow rates, high shear stress, have been documented with failure rates in excess of those attributed to FAC. These phenomena are described as erosion corrosion,[11)] impingement corrosion,[12)] and finally cavitation.[13)] All three phenomena result in a much more severe attack than what has broadly been called FAC, and which is at the basis of Checworks (see definitions below).

It is important to highlight this since the phenomena covered by Checworks do not include the most severe corrosion, which can occur particularly after a power upgrade. In fact Dr. Horowitz dismissed as irrelevant with respect to Checworks actual catastrophic failures attributed to erosion corrosion or impingement corrosion and therefore outside the scope of Checworks. This is a serious shortcoming of the

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[11)] This is actually a misnomer in this context since erosion corrosion generally involves solids carried in the fluid stream. However, it is recognized that the terminology is not used consistently. Erosion corrosion, which I prefer to characterize as FILC, starts at some unevenness on the surface (inclusion, scratch, etc.). The high flow rate causes local eddies, which leads to higher removal rate of corrosion product than over the surrounding areas. As the area of enhanced corrosion grows, the flow disturbance grows in intensity. Consequently the rate of penetration is not constant with time.

[12)] Impingement is caused by liquid droplets carried in the gas to hit the surface. This can occur from any angle depending on the direction of the flow vector. When a droplet approaches the surface the liquid between the droplet and the surface has to be displaced. It turns out that the velocity of the liquid parallel to the surface increases exponentially as the droplet approaches values many times higher than the estimated average velocity of the bulk liquid relative to the surface.

[13)] Cavitation occurs when the liquid flows relative to the surface (or the surface moves relative to the liquid) with oscillations such that at one point in time a vacuum is generated and a bubble is created, while right afterwards the pressure increases such that the bubble collapses. This causes enormously high oscillating fluid velocities parallel to the surface and tremendously increased mass transfer and very likely mechanical damage to the corrosion product layer (the passive layer) as well.

model and its application, because if the model forms the basis of aging management of the steam and hot water pipes it must, absolutely must, include the occurrence of all corrosion phenomena including those that lead to the most severe corrosion damage, not be restricted to just the average corrosion. But herein lies the rub as follows:

Checworks fully recognizes the fact that the severity of flow induced corrosion depends on geometric factors as described previously. Checworks, it appears, specifies in excess of 56 different geometric features. However there are things that cannot be specified. For example, the internal residual weld bead from the root pass may in one case be 1/8 inch high, in another ¼ inch. The upstream and downstream turbulence surrounding the weld bead are obviously much more severe in the latter case, and a power upgrade may disproportionately affect the flow over the larger bead.

While an increase in flow rate will affect the mass transfer rate (and hence the corrosion rate) proportionately under conditions of well defined (turbulent) flow, the flow intensity in local turbulences, such as eddies upstream and downstream of mechanical (geometric) flow disturbances are increased exponentially (see earlier). And here exactly is the uncertainty highlighted by Dr. Hopenfeld and denied by Dr. Horowitz. As I have also documented, industry consensus is that the flow intensity in local turbulences is increased to a much larger extent due to a power upgrade than the flow intensity in well-developed turbulent flow.

There are however additional phenomena, which have to be taken into account. Protective corrosion product layers can be destroyed not only through dissolution but by mechanical forces with turbulent areas. The fracture strength of corrosion product layers, such as iron sulfide and iron carbonate (highly protective formations), is extremely high (of the order of many hundreds of mega Pascals). Generally the compressive forces within turbulences are not that high.[14] It has been observed, however, that isolated events occur within the turbulences that match the fracture strength of the corrosion product scale. These events have led to the definition of a critical shear stress (or critical flow intensity) beyond which the protectiveness of the layer is lost. I am not suggesting that this absolutely happens. I am however postulating that past experience as built into Checworks cannot account for such occurrences. Therefore, the aging management process has to be revised or Checworks calibrated accordingly.

III. Discussion of Specific Experiences Involving Checworks

1. The Reliability of the Predictions

It has been said that Checworks can predict the "wear" [cumulative corrosion] within +/- 50 percent. If this were the case the modeling program would indeed be outstanding. However, the notion of predicted rates being with +/- 50% of the

[14] This discussion relates to the "freak waves" alluded to earlier (see ref. 2).

measured ones is derived from a representation of the data as shown in Figure 3 below. It is true that when the measured wear data are plotted against the predicted ones most of the data points lie between two lines that are plotted +/- 50% off the 45 degree equivalency lines. This interpretation is totally misleading and scientifically dishonest.

First, one sees that there is no correlation between the predictions and the actual measurements. Second, one also sees that measurements which we are made to believe are within 50% of the predicted value are really twice as large or larger; similarly, on the other side one sees that measured values are half or less of the predicted ones, again a factor of 2 different.

Conclusion: **The accuracy of Checworks is such that the measured values are within a factor of +/- two [+/- 2] of the predicted values rather than +/- 50% as claimed.**

A factor-of-two difference between measured and predicted corrosion [or corrosion rate] can be quite significant with respect to selecting a particular item (line) for inspection during a given refueling outage. Indeed the report of the "EPRI Checworks Wear Rate Analysis Results for Cycle 22B"[15)] shows that the time predicted to reach the critical minimum wall thickness in a majority of cases is many years *negative*. This means that the item should have failed a long time ago. Similarly, the remaining time to failure may be grossly overestimated. But one will never know unless the proper inspections are performed and the computer model recalibrated, a process Dr. Horowitz and Entergy seem to find irrelevant.[16)]

Examination of the data from March 2003 (RFO 23) showed average and measured corrosion rates of the order of 28 and 21 mpy, respectively, for the outlet "P-1-1A" on line 001-16-FDW-01. In May of 2006 these same rates have come down to 7.524 and 5.712 mpy, respectively.[17)] It is hard to see how this could have happened. There is in the program something called "Line Correction Factor." This factor has been defined by Dr. Horowitz as the relationship between predicted and measured corrosion rate (see below[18)]). However in 2003 this factor was 0.649 and by 2006 it had become 0.175. It is amazing to observe that fudge factors are built into the program which

[15)] Exhibit E-4-29.

[16)] Joint Declaration of Jeffrey S. Horowitz and James C. Fitzpatrick on NEC Contention 4-Flow-Accelerated Corrosion: A 34.

[17)] Exhibit E-4-30.

[18)] HOROWITZ'S TESTIMONY STATES THE FOLLOWING ABOUT THE ABOVE-MENTIONED "CORRECTION FACTOR" AT A28: "A Pass 2 Analysis compares the measured inspection results to the calculated wear rates and adjusts the FAC rate calculations to account for the inspection results. The program does this by comparing the predicted amount of degradation with the measured degradation for each of the inspected components. Using statistical methods, a correction factor is determined which is applied to all components in a given pipe line – whether or not they were inspected."

allow the operator to manipulate the data such that they meet certain criteria. (In the particular case mentioned above apparently negative times to failure were quite inconvenient).

Further examination of the data reveal that for the same line the corrosion rate on "Outlet P-1-1C" is exactly the same within 4 digits (+/- ~0.01 percent). Under the circumstances, it is very hard to gain confidence in Checworks and the manner in which it is apparently handled.

Finally it should be mentioned that with all the work that has been done, theoretical and empirical, around the problem of Flow Induced Localized Corrosion the matter is still not understood. In discussing the failure which occurred in April 2004 at the Kewaunee plant, Dr. Horowitz states that the line in question is not FAC-susceptible because apparently it is part of the "raw water system." Therefore it was not analyzed with Checworks and is not covered by NSAC-202L.

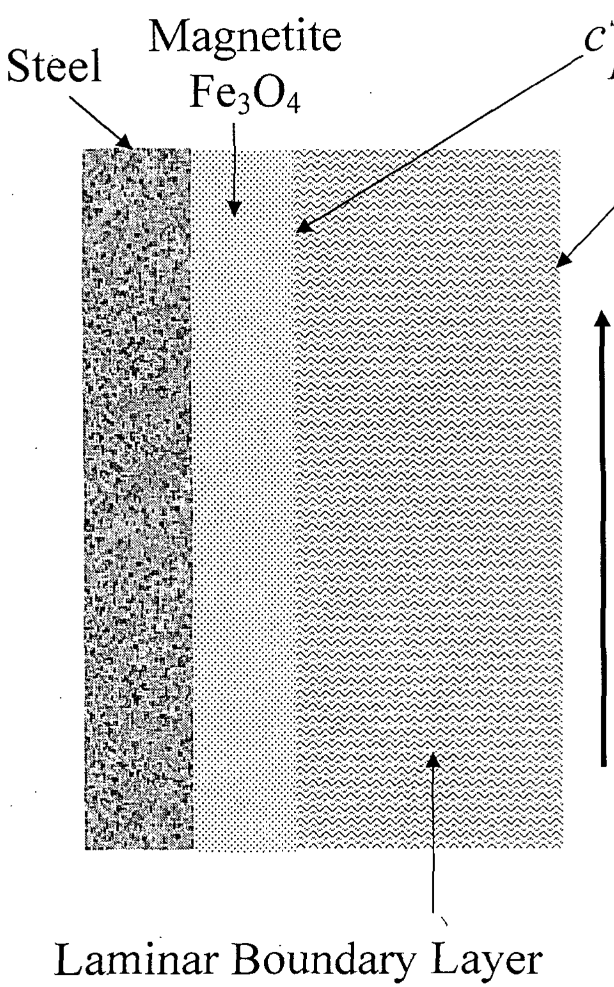
This is obviously a very unfortunate approach to the problem of corrosion in its entirety.

Whenever corrosion is dependent on transfer of corrosion products away from the surface, or transfer of corrodents to the surface, the corrosion rates are mass transfer dependent and hence flow dependent.

In the case of raw water, the oxygen content in the water is responsible for the observed corrosion. The corrosion rate is dependent on the oxygen concentration as well as on the flow rate. Flow rate dependence of corrosion is almost universally true except in a very few cases which are not relevant in this context.

Figure 1

The Concept of Flow Assisted Corrosion



$$c_{Fe^{n+}}^{sat} - c_{Fe^{n+}}^{bulk} = \Delta c \qquad Q = A \cdot \frac{\Delta c}{d}$$

Q = Rate of iron diffusion across laminar boundary sub-layer
A = diffusion coefficient for iron
d = boundary layer thickness

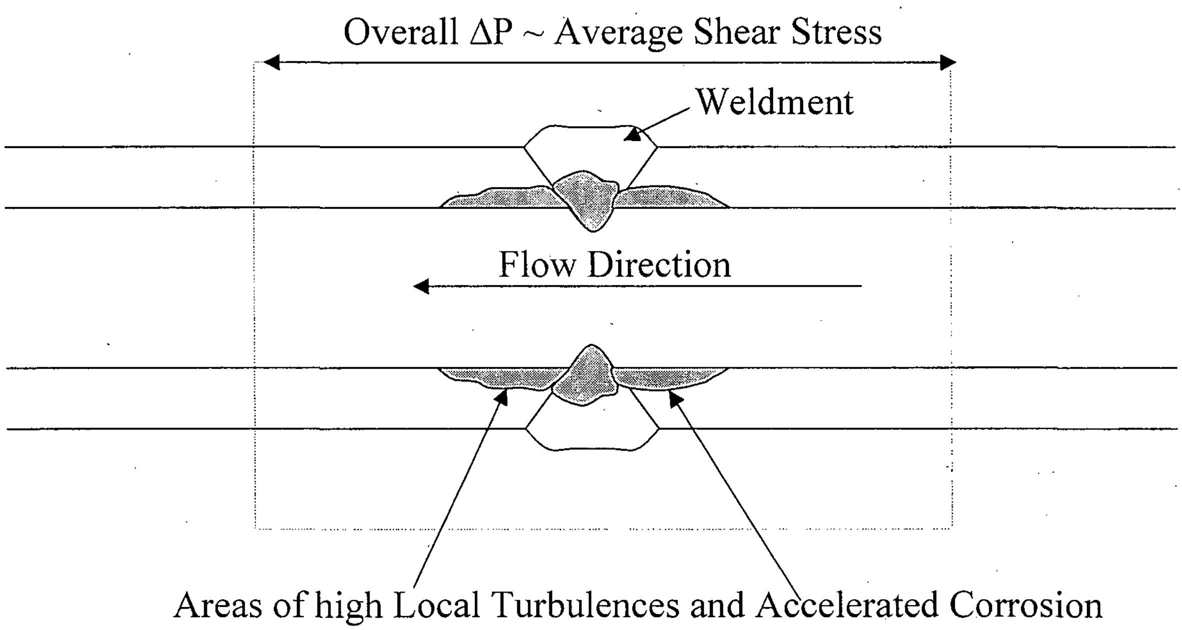
Bulk of solution; Direction of flow
Flow regime likely turbulent in the traditional sense
Re>>2000-3000

As the fluid velocity increases the thickness of the laminar layer decreases hence the mass transfer increases: removal Rate of iron oxide increases hence corrosion Rate increases.

Figure 2

Visualization of Average and Local Shear Stress

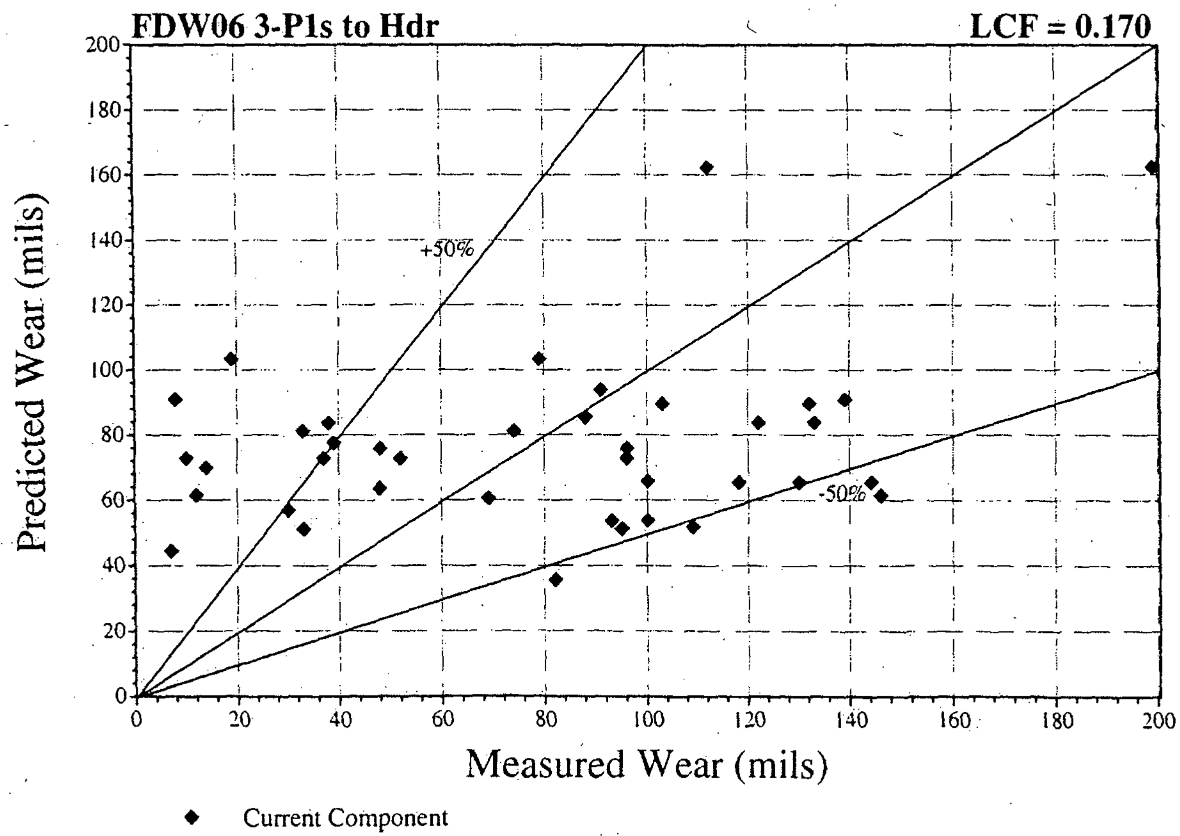
Straight Pipe with Weldment



The local shear stress is in no explicit relationship to the average shear stress
And can be orders of magnitude higher depending on geometric factors

Figure 3

Comparison of Wear Predictions



UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
Entergy Nuclear Vermont Yankee, LLC	)	Docket No. 50-271-LR
and Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-849-03-LR
	)	
(Vermont Yankee Nuclear Power Station)	)	

CERTIFICATE OF SERVICE

I, Christina Nielsen, hereby certify that copies of NEW ENGLAND COALITION, INC.'S REBUTTAL STATEMENT OF POSITION, TESTIMONY AND EXHIBITS in the above-captioned proceeding were served on the persons listed below, by U.S. Mail, first class, postage prepaid and, where indicated by an e-mail address below, by electronic mail, on June 2, 2008.

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June 2, 2008

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Re: In the Matter of Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Vermont Yankee Nuclear Power Station), Docket No. 50-271-LR, ASLBP No. 06-849-03-LR
Filing Discussing A Proprietary Document

Dear Sir or Madam:

Please find enclosed for filing in the above-stated matter New England Coalition, Inc.'s Rebuttal Statement of Position, Testimony and Exhibits. One document that Entergy has designated proprietary is discussed in the rebuttal testimony of Dr. Joram Hopenfeld, Exhibit NEC-JH_63.

This document is: Letter to James Fitzpatrick from EPRI (February 28, 2000). It is a letter to an Entergy staff person at the Vermont Yankee (VY) plant, stating EPRI's evaluation of the VY FAC program, and recommending certain changes to that program.

Pursuant to the Protective Order governing this proceeding, an unredacted version of this filing will be served only on the Board, the NRC's Office of the Secretary, Entergy's Counsel, and the following persons who have signed the Protective Agreement: Sarah Hoffman and Anthony Roisman. A redacted version of this filling will be served on all other parties.

Thank you for your attention to this matter.

Sincerely,

Karen Tyler

Karen Tyler
SHEMS DUNKIEL KASSEL & SAUNDERS PLLC

Cc: attached service list

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*Also admitted in the State of Maine
**Also admitted in the District of Columbia

UNITED STATES
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:

Alex S. Karlin, Chairman
Dr. Richard E. Wardwell
Dr. William H. Reed

In the Matter of	)	
	)	
ENTERGY NUCLEAR VERMONT YANKEE, LLC and ENTERGY NUCLEAR OPERATIONS, INC.	)	Docket No. 50-271-LR ASLBP No. 06-849-03-LR
	)	
(Vermont Yankee Nuclear Power Station)	)	

NEW ENGLAND COALITION, INC.
REBUTTAL STATEMENT OF POSITION

In accordance with 10 C.F.R. § 2.1207(a)(2) and the Atomic Safety and Licensing Board's ("Board") November 17, 2006 Order,[1] New England Coalition, Inc. ("NEC") hereby submits its Rebuttal Statement of Position ("Statement") on NEC's Contentions 2A and 2B (environmentally-assisted metal fatigue analysis), 3 (steam dryer), and 4 (flow-accelerated corrosion). In support of this Statement, NEC submits the attached rebuttal testimony of Dr. Joram Hopenfeld[2] and Dr. Rudolf Hausler,[3] and the Exhibits listed on the attached Rebuttal Exhibit List.

I. NEC CONTENTIONS 2A AND 2B

[1] Licensing Board Order (Initial Scheduling Order) (Nov. 17, 2006) at 10(D) (unpublished).

[2] Exhibit NEC-JH_63.

[3] Exhibit NEC-RH_04.

(Environmentally-Assisted Metal Fatigue Analysis)

The evidence contained in Entergy's and the NRC Staff's direct testimony and exhibits fails to prove the validity of Entergy's CUFen Reanalyses. Indeed, NRC Staff witness Dr. Chang has testified that the NRC Staff cannot determine the conservatism of Entergy's analysis, and must therefore rely on Entergy's proposed fatigue monitoring program to demonstrate its conservatism during the period of extended operation. *See,* Chang Rebuttal Testimony at A10. The Board should therefore decide Contentions 2A and 2B in NEC's favor. The Board should find that Entergy has failed to satisfy § 54.21(c)(1)(ii) by projecting its environmentally-assisted metal fatigue TLAA to the end of the period of extended operation, and therefore must now rely, pursuant to § 54.21(c)(1)(iii), on an aging management program to provide reasonable assurance of public health and safety. NEC should then be permitted to litigate its Contention 2, now held in abeyance, which addresses the sufficiency of Entergy's aging management plan for environmentally-assisted metal fatigue.

NEC's rebuttal evidence concerning Contentions 2A and 2B is contained in the prefiled rebuttal testimony of Dr. Joram Hopenfeld, Exhibit NEC-JH_63 at 2-19 and additional rebuttal Exhibits NEC-JH_64 – NEC-JH_67.

A. The NRC Staff Misconstrues the Requirements of 10 CFR § 54.21(c)(1).

The NRC Staff's ("the Staff") Initial Statement of Position misconstrues 10 CFR § 54.21(c)(1). By the Staff's construction of this rule, Entergy could resolve any of NEC's Contention 2A and 2B criticisms of the CUFen reanalyses through a commitment to continued "refinement" of these analyses after the close of the ASLB proceeding. The Staff's position is inconsistent with standard rules of statutory and regulatory construction, as well as with this Board's treatment of NEC's Contention 2, 2A and 2B in this proceeding to date. Most importantly, it would defeat the ability of any license renewal intervenor to litigate an applicant's Time Limited Aging Analysis ("TLAA") methodology.

Section 54.21(c)(1) allows a license renewal applicant three options to address an aging–related health and safety issue that it has evaluated under its current license through analysis that involves time-limited assumptions. It reads as follows:

> (c) An evaluation of time-limited aging analyses.
>
> (1) A list of time-limited aging analyses, as defined in § 54.3, must be provided. The applicant shall demonstrate that –
>
> > (i) The analyses remain valid for the period of extended operation;
> > (ii) The analyses have been projected to the end of the period of extended operation; or
> > (iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

10 CFR § 54.21(c). Under § 54.21(c)(1)(i), the applicant may demonstrate that the analysis performed under its current license is valid for the period of extended operation. If the applicant is unable to satisfy § 54.21(c)(1)(i), it may project the analysis to the end of the period of extended operation under § 54.21(c)(1)(ii). Finally, if the applicant is unable to demonstrate reasonable assurance of public health and safety through a TLAA analysis under § 54.21(c)(i) or § 54.21(c)(ii), it must then develop an aging management plan under § 54.21(c)(1)(iii).

Entergy's CUFen reanalyses are properly subject to 10 CFR § 54.21(c)(1)(ii) – Entergy has performed these reanalyses in an attempt to demonstrate that its CUFen TLAA has been projected to the end of the period of extended operation. This was the

NRC Staff's view in August, 2007. Then, the Staff rejected Entergy's license renewal commitment to complete its CUFen reanalyses prior to entering the period of extended operation on grounds that "in order to meet the requirements of 10 CFR § 54.21(c)(1), an applicant for license renewal must demonstrate in the LRA that the evaluation of the time-limited aging analyses (TLAA) has been completed." *See*, Exhibit NEC-JH_62 at Enclosure 2.

Now, however, the NRC Staff takes the position that Entergy's CUFen Reanalyses constitute a "corrective action" to "manage the effects of aging" that falls under 10 CFR 54.21(c)(1)(iii). The Staff has thus reversed its view of when Entergy must complete its CUFen reanalyses. It is now the Staff's opinion that Entergy may perform the CUFen Reanalysis as part of its aging management program after its license renewal application is granted, possibly even during the period of extended operation. The Staff explains:

> If a licensee chooses to satisfy § 54.21(c)(1)(i) or (ii), the 'demonstration' must be in the LRA, and a commitment to perform analyses projecting 60-year CUFs prior to the period of extended operation is inconsistent with the regulatory language. However, if the licensee chooses to satisfy § 54.21(c)(1)(iii), the licensee must instead demonstrate that effects of aging *will* be adequately managed and a commitment to perform refined CUF analyses in the future as part of an aging management program is acceptable.

NRC Staff Initial Statement of Position at 11-12 (emphasis in original).

The Staff's interpretation of § 54.21(c)(1) is inconsistent with its plain language, and with standard rules of construction. Part 54.21(c)(1)(iii) is properly interpreted as a requirement to manage aging in the event the TLAA cannot be projected to the end of the license renewal period. In other words, an applicant may avoid the obligation to develop an aging management plan under § 54.21(c)(1)(iii) if it satisfies § 54.21(c)(1)(i) or

54.21(c)(1)(ii) by including a demonstration that the TLAA is either valid or can be projected for the period of extended operation in the LRA. Under the NRC Staff's construction, parts 54.21(c)(1)(i) and 54.21(c)(1)(ii) collapse into part 54.21(c)(1)(iii): that is, the TLAA demonstration becomes a component of the aging management plan, instead of a means to avoid the obligation to develop an aging management plan. The Staff's construction is therefore invalid. *Cf,* Dunn v. CFTC, 519 U.S. 465, 472, 473, 117 S.Ct. 913, 137 L.Ed.2d 93 (1997) (rejecting an interpretation of a statute that would have left part of it "without any significant effect at all," because "legislative enactments should not be construed to render their provisions mere surplusage.").

The Staff's interpretation is also inconsistent with the Board's interpretation of NEC's Contentions 2, 2A and 2B in this proceeding to date, which treats Entergy's CUFen reanalyses as distinct from its metal fatigue aging management plan, and as an alternative to a management plan. The Board ruled that NEC's Contention 2 addresses the sufficiency of the metal fatigue management program. It held Contention 2 in abeyance, to be litigated only if NEC prevails on Contentions 2A and 2B, and Entergy then reverts to reliance on fatigue management. The Board's Order of November 7, 2007 reads in relevant part as follows:

> When this litigation began, Entergy's application showed certain CUFs to be greater than unity, and Entergy indicated that it would manage such metal fatigue over the 20-year renewal period. NEC's original Contention 2 challenged the adequacy of Entergy's demonstration of its metal fatigue management program. Now Entergy says it has recalculated the CUFs to show that they are all less than 1, thus eliminating the need to manage metal fatigue over the renewal period. NEC Contention 2A challenges Entergy's recalculation of the CUFs. If NEC Contention 2 is successful and Entergy's revised CUF analyses are not shown to be sufficient, then Entergy might return to relying on a fatigue management program as a way of satisfying the Part 54 regulations.

> Thus, we conclude that NEC Contention 2A will be litigated now, and NEC Contention 2 will be held in abeyance. The proviso is that the parties are not to litigate Contention 2 unless and until Entergy returns to reliance on a metal fatigue management program (as would likely happen if NEC prevails on NEC Contention 2A).

Memorandum and Order (Ruling on NEC Motions to File and Admit New Contention), November 7, 2007 at 12.

Finally, the Staff's position that Entergy's environmentally-assisted metal fatigue TLAA analysis should be treated as a component of its metal fatigue aging management plan under § 54.21(c)(1)(iii) has significant consequences for the rights of NEC and other license renewal intervenors to obtain information about and contest the validity of TLAAs. Per the Staff's view, the applicant may comply with § 54.21 through a commitment to perform the TLAA analysis after the application is granted, an approach that will obviously frustrate public scrutiny of the TLAA methodology.

These consequences are already playing out in the ASLB proceeding concerning Entergy's license renewal application for the Indian Point plant, in which both the State of New York and Riverkeeper, Inc. have petitioned for admission of a contention similar to NEC's Contention 2. Entergy has taken the positions that it should not be required to provide <u>any</u> information about its CUFen analyses for the NUREG/CR-6260 locations until after the close of the ASLB proceeding, and the Staff should accept a commitment to perform CUFen analyses as part of the Fatigue Monitoring Program per 10 CFR § 54.21(c)(1)(iii). *See,* Exhibit NEC-JH-67 at Attachment 1, Enclosure 2, (see discussion of D-RAI 4.3.1.8-1 and D-RAI 4.3.1.8-2). The NRC Staff has apparently acquiesced in Entergy's effort to avoid public scrutiny of its CUFen methodology, and withdrew requests for this information. Id.

The Board should reject the Staff's interpretation of 10 CFR § 54.21(c)(1). It should find that Entergy's CUFen Reanalyses fall under § 54.21(c)(1)(ii), and must be completed as part of Entergy's License Renewal Application. The Board should further find that Entergy cannot satisfy § 54.21(c)(1) with a license renewal commitment to fix any problems in its CUFen Reanalyses, demonstrate the conservatism of those analyses, or finish those analyses after the close of the ASLB proceeding.

B. <u>Entergy's Evidence Does Not Include Information Necessary to Validate its CUFen Reanalyses; Entergy Therefore Fails to Satisfy its Burden of Proof.</u>

Dr. Hopenfeld testifies that Entergy has not provided to NEC or filed in the evidentiary record before the Board the following information necessary to validate its CUFen Reanalyses:

1. Drawings of the VY plant piping from which it would be possible to validate Entergy's assumptions of uniform heat transfer distribution, including orientation angles, weld locations and internal diameters, Hopenfeld Rebuttal at A18, Exhibit NEC-JH_03 at 8;

2. A complete description of the methods or models used to determine velocities and temperatures during transients, Hopenfeld Rebuttal at A19, Exhibit NEC-JH_03 at 9; and

3. Information regarding exactly how the number of plant transient cycles was determined for purposes of the 60-year CUF calculations, from which it would be possible to evaluate the conservatism of the cycle count, Hopenfeld Rebuttal at A21.

Regarding the first two issues, Entergy represents that some information was provided: 36 drawings, a copy of the Design Information Record, and some information regarding the calculation of flow velocity in response to Counsel's inquiry. Entergy Initial Statement of Position at 14. Dr. Hopenfeld testifies that the information Entergy provided is insufficient. Hopenfeld Rebuttal at A18 and A19.

Entergy further faults NEC for failing to request any additional information it considered necessary to a complete evaluation of the CUFen analyses in "discovery." Id. This argument of course ignores the fact that, to its tremendous disadvantage, NEC has no right to formal discovery in this Subpart L proceeding. *See,* 10 CFR § 1.1203, Hearing file; prohibition on discovery; *In the Matter of Entergy Nuclear Vermont Yankee, LLC, and Entergy Nuclear Operations, Inc. (Vermont Yankee Nuclear Power Station)*, 64 NRC 131, 202, ASLBP 06-849-03-LR, (September 22, 2006)("under the 'informal' adjudicatory procedures of Subpart L, discovery is prohibited except for certain mandatory disclosures.").

More importantly, Entergy's argument that NEC should have requested information in fictitious "discovery" misses the point. Entergy has the burden of proof regarding whether its CUFen reanalyses satisfy 10 CFR § 54.21(c)(1)(ii), and provide reasonable assurance of public health and safety. Entergy does not even attempt to explain why its record evidence concerning the VY pipe configuration and the methods or models it used to determine velocities and temperatures during transients is sufficient to validate its CUFen reanalyses. Entergy therefore fails to meet its burden.

With respect to the third issue above, the transient cycle count, Dr. Hopenfeld testifies that the explanation stated in Entergy's direct testimony of its means of determining the number of plant transients for purposes of its CUF calculations is inconsistent with information Entergy provided in its LRA and in the reports of the CUFen analyses produced to NEC. Hopenfeld Rebuttal at A21. Entergy's direct testimony on this subject is vague, and does not indicate that an allowance was made for the likely increase in plant transients resulting from the 20 percent power uprate or the fact that the number of plant transients is likely to increase as a plant ages. Id. Dr. Hopenfeld is unable to determine whether Entergy's transient cycle count is conservative. Id.

The NRC Staff's Initial Statement of Position misrepresents the testimony of NRC Staff witness Dr. Chang with respect to the transient cycle count. The Statement of Position represents that the Staff "disagrees with NEC's assertion that Entergy's assumptions about the number of transients in its analyses are not conservative," and states that "[t]he Staff's position is that Entergy's assumptions are appropriate." NRC Staff Initial Statement of Position at 18. In fact and to the contrary, Dr. Chang testifies that the staff, like Dr. Hopenfeld, "cannot determine the level of conservatism regarding the number of transient cycles at this time," and therefore relies on Entergy's Fatigue Monitoring Program to "ensure that the cycle projection is valid **<u>and that the fatigue analysis results are conservative</u>**." Chang Rebuttal at A10 (emphasis added).

Thus, per the testimony of NRC Staff witness Dr. Chang, Entergy has not provided information to the NRC, or filed evidence before the Board, from which it is possible to determine whether its CUFen analysis results are conservative. Again, Entergy has not satisfied its burden of proof, and the Board must decide Contentions 2A and 2B in NEC's favor.

C. <u>Calculation of the Fen Multiplier</u>

1. <u>The NRC Staff and Entergy are Incorrect that the ASME Code Does Not Require the Fen Correction.</u>

Both Entergy and the NRC Staff contend that the ASME Code does not require any accounting for the effects of coolant environment on component fatigue life. This is incorrect. The Code requires that **the code user must account** for conditions in which the environment is more aggressive than air. Rebuttal Testimony of Joram Hopenfeld at A5, *citing*, ASME Code, Appendix B at B-2131.

2. NRC Staff guidance that sanctions use of the equations and procedure described in NUREG/CR-6583 and NUREG/CR-5704 to calculate Fen multipliers is not dispositive. The Staff must prove the validity of this guidance, but has not done so.

In response to Dr. Hopenfeld's argument that Entergy used outdated statistical equations published in NUREG/CR-6583 and NUREG/CR-5704 to calculate Fen values, when it should have instead considered data much more recently published in NUREG/CR-6909 (February 2007), both the NRC Staff and Entergy cite NRC guidance stated in Section X.M1 of the GALL Report, NUREG-1801, Vol. 1, which sanctions use of the NUREG/CR-6583 and NUREG/CR-5704 equations to calculate Fen multipliers. Entergy and the Staff also note that Regulatory Guide 1.207 recommends reference to NUREG/CR-6909 only for fatigue analyses in new reactors.

These guidance documents are by no means dispositive of NEC's criticisms of Entergy's method of calculating Fen values. "Agency interpretations and policies are not 'carved in stone' but must rather be subject to re-evaluation of their wisdom on a continuing basis." *Kansas Gas and Electric Co. (Wolf Creek Generating Station, Unit 1)*, 49 NRC 441, 460 (1999), *citing*, *Chevron USA, Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 863-64 (1984)).

The GALL report and Regulatory Guide 1.207 do not contain legally binding regulatory requirements. The Summary and Introduction to NUREG-1801, Vol. 1 includes the following explanation of its legal status:

> Legally binding regulatory requirements are stated only in laws; NRC regulations; licenses, including technical specifications; or orders, not in NUREG series publications.
>
> * * *
>
> The GALL report is a technical basis document to the SRP-LR, which provides the Staff with Guidance in reviewing a license renewal application . . . . ***The Staff should also review information that is not addressed in the GALL report or is otherwise different from that in the GALL report.***

NUREG-1801, Vol. 1, Summary, Introduction, Application of the GALL Report (emphasis added). Likewise, the face page to Regulatory Guide 1.207 states the following: "Regulatory Guides are not substitutes for regulations, and compliance with them is not required." Regulatory Guide 1.207; *See also, In the Matter of International Uranium (USA) Corporation*, 51 NRC 9, 19 (2000) ("[NRC NUREGS, Regulatory Guides, and Guidance documents] are routine agency policy pronouncements that do not carry the binding effect of regulations. . . .").

NUREG-1801, Vol. 1 and Regulatory Guide 1.207 do not preclude this Board from considering the question at the heart of NEC's Contentions 2A and 2B: What is the most appropriate method of calculating the effects of the environment on fatigue?

> [NUREGs] do not rise to the level of regulatory requirements. Neither do they constitute the only means of meeting applicable regulatory requirements. . . . ***Generally speaking, . . . such guidance is treated simply as evidence of legitimate means for complying with regulatory requirements, and the staff is required to demonstrate the validity of its guidance if it is called into question during the course of litigation.***

In the Matter of Carolina Power & Light Company and North Carolina Eastern Municipal Power Agency (Shearon Harris Nuclear Power Plant), 23 NRC 294 (1986), *citing, Metropolitan Edison Co. (Three Mile Island Nuclear Station, Unit 1)*, 16 NRC 1290, 1298-99 (1982) (emphasis added); *See also, In the Matter of Connecticut Yankee*

Atomic Power Company (Haddam Neck Point), 54 NRC 177, 184 (2001), *citing, Long Island Lighting Co. (Shoreham Nuclear Power Station, Unit 1)*, 28 NRC 288, 290 (1988)("NUREGs and similar documents are akin to 'regulatory guides.' That is, they provide guidance for the Staff's review, but set neither minimum nor maximum regulatory requirements."); *In the Matter of Private Fuel Storage, LLC,* 57 NRC 69, 92 (2003)("[A]n intervenor, though not allowed to challenge duly promulgated Commission regulations in the hearing process. . . is free to take issue with . . . NRC Staff guidance and thinking . . . .").

The Staff is required in this proceeding to prove the current validity of its guidance concerning the calculation of Fen multipliers, but has produced little if any evidence of this. Entergy and the NRC Staff offer only one substantive reason[4] for use of the NUREG/CR-6583 and NUREG/CR-5704 equations over information contained in NUREG/CR-6909: both contend that the NUREG/CR-6909 "procedure" is less conservative and will generally produce lower Fen multipliers for operating reactors. *See,* Fair Rebuttal at A5 and A6, Stevens Rebuttal at A50. Dr. Hopenfeld explains that the overall NUREG/CR-6909 "procedure" could be considered less conservative because NUREG/CR-6909 contains new air fatigue curves that are less conservative that the current ASME Code fatigue curves. Hopenfeld Rebuttal at A6. He further testifies, however, that he has never recommended use of these new air fatigue curves. Until the current fatigue curves in the Code are officially modified, these curves must be considered the "best representation of fatigue life in air." Id.

[4] The Staff also offers a nonsubstantive reason: i.e., that it would be inconvenient to change its guidance while a number of license renewal applications are pending or anticipated.

Dr. Hopenfeld explains that the alleged greater conservatism of the NUREG/CR-6583 and NUREG/CR-5704 "procedure" is irrelevant to his main point about how Entergy should have used information contained in NUREG/CR-6909 in its CUFen analyses. Hopenfeld Rebuttal at A6, A7. As Dr. Hopenfeld has previously testified, NUREG/CR-6909 describes many factors known to affect fatigue life that are not accounted for in the ANL 1998 Equations contained in NUREG/CR-6583 and NUREG/CR-5704. Dr. Hopenfeld's rebuttal testimony provides a summary of these factors at A5, Table 1, and observes that Entergy's direct testimony addresses only one of them, surface finish. Hopenfeld Rebuttal at A5. This is the relevant information Entergy should have taken from NUREG/CR-6909. Hopenfeld Rebuttal at A7. Entergy and NRC staff witnesses fail to explain why this information contained in NUREG/CR-6909, published after the GALL report, should be ignored in the license renewal process.

Dr. Hopenfeld testifies that, given the current state of the technology, it simply is not possible to calculate Fen multipliers that are precision-adjusted to plant conditions, as Entergy purports to have done. Hopenfeld Rebuttal at A7. Given the many uncertainties in the calculation of Fen, he recommends use of bounding values contained in NUREG/CR-6909 – 12 for austenitic stainless steel and 17 for carbon and low alloy steel. Id.

3. NEC's Rebuttal Evidence Concerning Calculation of Fen Multipliers

NEC witness Dr. Joram Hopenfeld's rebuttal testimony addresses the following additional technical issues regarding the calculation the Fen multipliers raised by Entergy and the NRC Staff.

- Dr. Hopenfeld disagrees with NRC witness Dr. Chang that Fen values of 12 for austenitic stainless 17 for carbon and low alloy steel represent a "worst case scenario," or that application of these values is unreasonably conservative. Hopenfeld Rebuttal at A9.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Stevens that Fen=17 applies only to high oxygen and temperature environments that do not exist at VYNPS. Hopenfeld Rebuttal at A10.

- Dr. Hopenfeld does not agree with Entergy and NRC Staff witnesses that any lack of conservatism in Fen values calculated by the ANL 1998 Equations is counterbalanced by excess conservatism in the ASME Code design fatigue curves. He observes that there is no general agreement among researchers that the current Code is conservative. Hopenfeld Rebuttal at A12.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Fitzpatrick that Entergy properly accounted for surface roughness effects through use of ASME Code design fatigue curves that include a "safety factor" to account for these effects. Hopenfeld Rebuttal at A13.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Fitzpatrick that Entergy has demonstrated its use of bounding values for oxygen as an input to the ANL equations in all its CUFen analyses. Hopenfeld Rebuttal at A14. Mr. Fitzpatrick refers to steady state values as determined by a computer Code called BWRVIA that Entergy has neither described nor provided to NEC. Id. Mr. Fitzpatrick does not address the impact on Fen of oxygen concentrations that occur during transients at higher levels than at steady state. Id.

- Dr. Hopenfeld testifies that it was inappropriate for Entergy to exclude a correction factor for cracking in the cladding and base metal of the feedwater nozzles based on results of its 2007 inspection of these nozzles for cracks in the base metal. Hopenfeld Rebuttal at A15.

D. <u>Calculation of 60-Year CUFs</u>

NEC witness Dr. Joram Hopenfeld's rebuttal testimony addresses the following issues, in addition to the above-discussed potential lack of conservatism in projecting transient cycles, regarding the calculation the 60-year CUFs raised by Entergy and the NRC Staff.

- Dr. Hopenfeld disagrees that Entergy's CUFen analyses properly applied a heat transfer equation that applies only to a fully developed turbulent flow to the VYNPS nozzles. Specifically, he disagrees with Entergy witness Mr. Stevens that flow in the feedwater nozzle is fully developed because the upstream horizontal pipe is 48 inches long. Hopenfeld Rebuttal at A16. Dr. Hopenfeld further observes that Mr. Stevens did not explain why, in transients where the flow stops and heat transfer occurs by natural convection, a correction was not made for circumferential variation of the heat transfer both during single phase flow and during condensation. Id.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Stevens that it is unnecessary to correct a heat transfer equation used in the CUFen Reanalyses by the ratio of the viscosities evaluated at the bulk and wall temperatures during each transient because there are minimal differences in temperature between the pipe wall and the bulk of the fluid. Hopenfeld Rebuttal at A17. Mr. Stevens did not quantify actual temperature differences, which could only be determined from data on wall and bulk fluid temperature histories for sample transients. Id. Such information was not provided. Id.

- Dr. Hopenfeld disagrees that Entergy's use of the simplified Green's Function methodology in its Initial CUFen Reanalysis introduced only a small error. Hopenfeld Rebuttal at A20. Entergy has neither explained nor investigated the physical reasons for discrepancies between results obtained by the Green's Function methodology and the more exact methodology, classic NB-3200 analysis. Id. Results obtained by the Green's Function methodology therefore incorporate <u>unquantified</u> uncertainties. Id.

E. <u>Error Analysis</u>

NEC witness Dr. Joram Hopenfeld's rebuttal testimony addresses the following issues regarding the need for error analysis raised by Entergy and the NRC Staff.

- Dr. Hopenfeld disagrees with Entergy's witness that it was not necessary to perform an error analysis to validate its analytical techniques because the stress analysis is based on bounding values. Hopenfeld rebuttal at A23.

- Dr. Hopenfeld disagrees with NRC witness Dr. Chang that an error analysis was unnecessary because of conservatism built into the ASME Code and the ANL 1998 Equations. Hopenfeld Rebuttal at A24.

III. NEC CONTENTION 3 (Steam Dryer)

NEC's rebuttal evidence concerning Contention 3 is contained in the prefiled rebuttal testimony of Dr. Joram Hopenfeld, Exhibit NEC-JH_63 at 20-24, and additional rebuttal Exhibits NEC-JH_68 and NEC-JH_69.

A. <u>The Issue Before the Board is Whether a Steam Dryer Aging Management Plan Uninformed by Knowledge of Stress Loads on the</u>

Dryer for Comparison to Fatigue Limits is Adequate to Provide Reasonable Assurance of Public Safety.

The validity of the steam dryer stress load modeling Entergy conducted during implementation of the VY power uprate as a basis for Entergy's steam dryer aging management plan during the period of extended operations has not been litigated in this proceeding or otherwise established. The Board has ruled that the assessment of this modeling conducted during the EPU proceeding was not dispositive for purposes of life extension:

> Entergy's apparent assertion that the history of the steam dryer issue in the separate EPU proceeding should resolve the issue in this proceeding is . . . without foundation. As demonstrated by Entergy's own pleadings, steam dryer issues were addressed in the EPU proceeding primarily in regard to the power ascension toward EPU levels and the first few operating cycles thereafter.

In the Matter of Entergy Nuclear Vermont Yankee, LLC, and Entergy Nuclear Operations, Inc. (Vermont Yankee Nuclear Power Station), 64 NRC 131, 189 (September 22, 2006).

Moreover, Entergy represented in its Motion for Summary Disposition of NEC's Contention 3 that its steam dryer aging management program will consist exclusively of periodic visual inspection and monitoring of plant parameters as described in General Electric Service Information Letter 644 (GE-SIL-644), will not involve the use of any analytical tool to estimate stress loads on the steam dryer, and will not rely on the finite element modeling conducted prior to implementation of the extended power uprate (EPU) in 2006 for knowledge of steam dryer stress loads.

In partially granting Entergy's Motion for Summary Disposition, the Board accepted Entergy's representation that its steam dryer aging management plan would not rely on the pre-EPU steam dryer modeling. Memorandum and Order (Ruling on Motion for Summary Disposition of NEC Contention 3), September 11, 2007 at 10 ("Entergy's expert confirms that this program does not require the use of the CFD and ACM computer codes or the finite element modeling conducted during the EPU."). In doing so, the Board rejected NEC's argument that it should be permitted to litigate the validity of the EPU steam dryer modeling as the basis for aging management. NEC's pleading in opposition to Entergy's Motion for Summary Disposition stated the following regarding this issue:

> As stated in the attached Third Declaration of Dr. Joram Hopenfeld, Entergy's claim that its steam dryer aging management program will not involve any means of estimating and predicting stress loads on the dryer simply is not credible. Exhibit 1, Third Declaration of Dr. Joram Hopenfeld ("Hopenfeld Declaration 3") ¶ 6. A valid steam dryer aging management program must include some means of estimating and predicting stress loads on the steam dryer, and determining that peak loads will fall below ASME fatigue limits. Hopenfeld Declaration ¶ 5.
>
> Entergy represents that it did conduct this analysis as part of the Vermont Yankee EPU power ascension testing using the ACM and CFD models. Hoffman Declaration ¶¶ 11-13. Entergy now proposes sole reliance on visual inspection and plant parameter monitoring during the renewed license period. Such reliance must be based on Entergy's previous ACM/CFD-based predictions that stress loads on the dryer will not cause fatigue failures. Hopenfeld Declaration ¶ 7. NEC's concerns regarding the validity of the ACM and CFD models and the stress and fatigue analysis Entergy conducted using these models therefore remain current and relevant.

New England Coalition, Inc.'s Opposition to Entergy's Motion for Summary Disposition of NEC's Contention 3 (Steam Dryer) (May 9, 2007) at 4.

Both Entergy and the NRC Staff now contend that Entergy's steam dryer aging management program *does* in fact rely on the steam dryer modeling conducted during EPU implementation for knowledge of dryer stress loads. *See,* Entergy Initial Statement of

Position at 32 ("[T]he loadings on the dryer derive from plant geometries . . . that have not changed since the uprate was implemented, so there has been no change to the loadings on the dryer and the resulting stresses. Therefore, there is no reason to provide continued instrumentation to measure loadings or further analytical efforts."); NRC Staff Initial Statement of Position at 19 (The Staff's position is that stress analysis as a means of estimating and predicting stress loads during operations "is not necessary because the results of the EPU power ascension program demonstrated that the pressure loads during the EPU operations do not result in stress on the steam dryer that exceed ASME fatigue stress limits.").

In light of the above-discussed procedural history, and Entergy's prior representations, the Board must disregard these current contentions that the modeling of the dryer during the EPU power ascension program is a proper basis for aging management. This issue has not been determined, and the Board took it off the table in its decision of Entergy's Motion for Summary Disposition. The issue now properly before the Board is whether an aging management plan that consists solely of plant parameter monitoring, and partial visual inspection, uninformed by knowledge of dryer loading, can provide reasonable assurance of public safety.

B. Hopenfeld Rebuttal

Dr. Joram Hopenfeld provides the following rebuttal testimony regarding the above-stated issue properly before the Board.

■ Dr. Hopenfeld testifies that the ability to estimate the probability of formation of loose parts requires knowledge of the cyclic loads on the dryer to ensure that the dryer is not subjected to cyclic stress that would exceed the endurance limit. Hopenfeld Rebuttal at A28.

- Dr. Hopenfeld observes that Mr. Hoffman and Mr. Lukens do not provide a single quantitative assessment in support of this position, discussed in A56-62 of their testimony, that the inspection programs at VY ensure that the dryer will not fail. Id.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Lukens that "operating experience after the EPU (exemplified by the data collected during the 2007 inspection and the subsequent year of monitoring of plant operating parameters) demonstrates that the stresses experienced by the dryer are insufficient to initiate and propagate fatigue cracks." Hopenfeld Rebuttal at A29.

- Dr. Hopenfeld provides a section of the Entergy Condition Report previously filed as Exhibit NEC-JH_59 that includes General Electric's statement that "continued [steam dryer crack] growth by fatigue cannot be ruled out." This section of the Condition Report was previously inadvertently excluded due to a clerical error. Hopenfeld Rebuttal at A29. Dr. Hopenfeld also disagrees with Entergy witness Mr. Lukens that the inspection photographs provided in Entergy's Condition Report, Exhibit NEC-JH59 at 2-8, show that the cracks are inactive. Metallographic examinations would be required to demonstrate this, not remote camera photos. Hopenfeld Rebuttal at A31.

- Dr. Hopenfeld observes that IGSCC cracks that now exist in the VY steam dryer can provide sites for corrosion attack which would in turn accelerate crack growth under cycling loading. The rate of crack propagation would depend on load intensities and duration. Id.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Hoffman that design basis loads ("DBA") cannot cause dryer failure. Hopenfeld Rebuttal at A32.

- Dr. Hopenfeld disagrees with Entergy witness Mr. Hoffman that it is not necessary to estimate and predict dryer stresses because "[c]onfirmation that stresses on the VY steam dryer remain within fatigue limits is provided daily by the fact that the dryer has been able to withstand without damage the increased loads imparted on it during power ascension and for the two years of operation since EPU was implemented." Hopenfeld Rebuttal at A33. Vibration fatigue is a time-related phenomenon; the fact that the dryer has not failed to date is not at all an indication that it will not fail in the future. Id.

- Dr. Hopenfeld testifies that Entergy has not provided a quantitative estimate of the probability of crack detection, but should have done so, since the entire dryer is not accessible to visual inspection. Hopenfeld Rebuttal at A35.

IV. NEC CONTENTION 4 (Flow-Accelerated Corrosion)

NEC's rebuttal evidence concerning Contention 4 is contained in the prefiled rebuttal testimony of Dr. Joram Hopenfeld, Exhibit NEC-JH_63 at 24-41; additional rebuttal Exhibits NEC-JH_70– NEC-JH_72; the prefiled rebuttal testimony of Dr. Rudolf Hausler, Exhibit NEC-RH_04; and Dr. Hausler's report titled "Flow Assisted Corrosion (FAC) and Flow Induced Localized Corrosion: Comparison and Discussion," Exhibit NEC-RH_05.

Entergy witness Dr. Horowitz has testified that it is not necessary to recalibrate or "benchmark" the CHECWORKS model with plant inspection data following a twenty percent power uprate. Joint Declaration of Jeffrey S. Horowitz and James C. Fitzpatrick on NEC Contention 4 – Flow-Accelerated Corrosion at A33, 34. Rather, Dr. Horowitz contends that the only update to the CHECWORKS model that is necessary following a twenty percent power uprate is the input of new values for flow rate and temperature into the model. Horowitz at A33, 34. Dr. Horowitz bases these assertions on his view that "[flow-accelerated corrosion (FAC)] wear rates vary roughly with velocity and do not increase with velocity in [a] non-linear (exponential) manner. . . .", Horowitz at A49, and his beliefs that FAC is not fundamentally a local phenomena, and the CHECWORKS model can accurately predict any variations in FAC rates related to geometric features. Dr. Horowitz contends that the CHECWORKS model accounts for any localized variations in FAC associated with geometric features through the use of "'geometric factors' to relate the maximum degradation occurring in a component, such as an elbow, to the degradation predicted to occur in a straight pipe." Horowitz at A47, A48.

Dr. Hopenfeld and Dr. Hausler disagree with Dr. Horowitz that recalibration of the CHECWORKS model is unnecessary following substantial changes in flow velocity and changes in temperature, and respond regarding Dr. Horowitz's grounds for this opinion as follows.

- Dr. Hausler testifies that the linear relationship between FAC rates and fluid velocity transitions to an exponential one as the local turbulence becomes such that erosional features become manifest. Whether such transition actually occurs when flow velocity increases following a power uprate must be determined experimentally. Hausler Rebuttal at A5, Exhibit NEC-RH_05.

- Dr. Hopenfeld stresses that "FAC is fundamentally a local phenomenon due to variations of local turbulence in curved pipe, nozzles, tees, orifices, etc," and that corrosion rates can be expected to "vary with location depending on the intensity of the local turbulence." Hopenfeld Rebuttal at A42, A52, A53, A54 He also disagrees with Dr. Horowitz that the rate of FAC corresponds weakly with the velocity, and varies less than linearly with time, and disputes the relevance of the data Dr. Horowitz cites in support of his position. Hopenfeld Rebuttal at A41, A46, A53, A55.

- Dr. Hausler does not agree that the CHECWORKS model, or any model, can fully account for variations in the rate of FAC due to geometric features and discontinuities. Hausler Rebuttal at A6; Exhibit NEC-RH_05. Some things cannot be specified. For example, the internal residual weld bead from the root pass may be 1/8 *inch high in one case, and ¼ inch high in another case.* Id. The upstream and downstream turbulence surrounding the weld bead will be more severe in the latter case, and a power uprate may disproportionately affect the flow over the larger bead. Id.

- Dr. Hopenfeld observes that, while Dr. Horowitz denies the need to recalibrate CHECWORKS, he recognizes the need to increase the FAC inspection scope by 50% to account for the power uprate. Hopenfeld Rebuttal at A48. Entergy does not disclose what fraction of the total FAC susceptible area in the VY plant the proposed increased monitoring would represent, and its significance is therefore entirely unclear. Id.

Both Dr. Hopenfeld and Dr. Hausler take issue with Dr. Horowitz's definition of FAC as corrosion in proportion to the flow rate, Horowitz at A46, and observe that this definition excludes the more severe forms of localized corrosion – erosion-corrosion, impingement and cavitation. Hausler Rebuttal at A6; Exhibit NEC-RH_05; Hopenfeld Rebuttal at A45. Both Hopenfeld and Hausler observe that this definition of FAC is entirely arbitrary. Erosion-corrosion, impingement and cavitation are extensions of FAC as the local flow intensity due to turbulence increases. The transition from one to the others is continuous and difficult to identify. Id. If CHECWORKS is unable to predict these more severe forms of localized corrosion related to high flow rates, which can particularly occur after a power uprate, then this is a serious shortcoming of the model and its application. Id.

Dr. Hausler and Dr. Hopenfeld also address the following additional issues:

- Dr. Hausler observes that the accuracy of CHECWORKS has been said to be within +/- 50%, but this statement is based on an erroneous interpretation of the graphic representation of predicted vs. measured wear. Hausler Rebuttal at A6; Exhibit NEC-RH_05. Actually, the accuracy is within a factor of 2 – the measured wear rates range from twice the prediction to half the prediction. Id. A factor of two difference between measured and predicted corrosion [or corrosion rate] can be quite significant with respect to selecting a particular item (line) for inspection during a refueling outage. Id.

- Dr. Hopenfeld disagrees with Dr. Horowitz's evaluation of industry FAC experience, and his contention that this experience demonstrates the efficacy of CHECWORKS. Hopenfeld Rebuttal at A39, A40, A49, A52, A53. Dr. Hopenfeld specifically disagrees that, in assessing industry FAC experience, a distinction should be drawn between pipe failures due to leaks and failures due to ruptures. Hopenfeld Rebuttal at A44, A53.

- Dr. Hopenfeld faults Entergy for its failure to specify the total FAC-susceptible area that is inspected during a typical outage. Hopenfeld Rebuttal at A43.

- Dr. Hopenfeld disputes Dr. Horowitz's suggestion that the oxygen concentration at VY did not change in 2003. Hopenfeld Rebuttal at A51.

V. CONCLUSIONS

Extended operation of VYNPS as Entergy has proposed in its LRA will jeopardize public health and safety. The LRA should be denied unless the important issues addressed by NEC's Contentions 2A, 2B, 3 and 4 are resolved.

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