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DOCKETED
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June 27, 2008 (2:10pm)

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

June 27, 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 Proprietary Documents

Dear Sir or Madam:

Please find enclosed for filing in the above-stated matter New England Coalition, Inc.'s Motion to File Corrections to Exhibits and to Withdraw Certain Testimony of Ulrich Witte. This filing attaches an expert witness report, NEC-UW_03, which discusses the following documents that Entergy has designated proprietary, all of which NEC has previously filed in this proceeding:

1. Recommendations for an Effective Flow-Accelerated Corrosion Program (NSAC-202L-R3);

2. EPRI: Recommendations for FAC Tasks;

3. Letter to James Fitzpatrick from EPRI (February 28, 2000); and

4. Letter from Entergy to NRC re. Extended Power Uprate: Response to Request for Additional Information.

The first two documents are EPRI guidance documents for flow-accelerated corrosion programs. The third 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. The fourth is Entergy's response to a NRC Staff Request for Additional Information concerning issues related to Entergy's VYNPS EPU application.

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*Also admitted in the State of Maine
**Also admitted in the District of Columbia

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

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's MOTION TO FILE CORRECTIONS TO EXHIBITS AND TO WITHDRAW CERTAIN TESTIMONY OF ULRICH WITTE

Pursuant to 10 CFR § 2.323, New England Coalition, Inc. ("NEC") hereby moves to file corrections to Ulrich Witte's report, Exhibit NEC-UW_03, and corrected versions of Exhibits NEC-UW_15 and NEC-UW_20. NEC also moves to withdraw portions of Mr. Witte's report, Exhibit NEC-UW_03, and of Mr. Witte's direct and rebuttal testimony that concern Entergy's alleged reduction of the number of FAC inspection data points between the 2005 refueling outage and the 2006 refueling outage.

I. Motion to File Corrections to Exhibit NEC-UW_03 and Corrected Versions of Exhibits NEC-UW_15 and NEC-UW_20

In the process of responding to Motions in Limine to exclude from the record Mr. Witte's report, Exhibit NEC-UW_03, filed April 28, 2008, Mr. Witte identified and corrected a number of citation errors in this report. These errors involved the transposition of exhibit numbers and other clerical mistakes. Mr. Witte also determined that one of his Exhibits, NEC-UW_15, is incomplete; and a second, NEC-UW_20, was printed from a corrupted file.[1] Mr. Witte completed a corrected version of his report, Exhibit NEC-UW_03, on June 19, 2008. NEC filed both this corrected report and corrected versions of Mr. Witte's Exhibits NEC-UW_15 and NEC-UW_20 on June 19, 2008, as Attachment A to NEC's Opposition to Entergy's Motion in Limine. The corrected report and exhibits are attached hereto as Attachment A.

This motion is timely filed within ten days of the date Mr. Witte completed corrections to his report. 10 CFR § 2.323(a). Mr. Witte's corrections do not change the substance of his report or testimony. The substitution of the corrected report and exhibits therefore is not prejudicial to the other parties.

II. Motion to Withdraw Certain Testimony of Ulrich Witte

NEC moves to withdraw portions of the Prefiled Direct Testimony of Ulrich Witte Regarding NEC Contention 4, of Mr. Witte's report, Exhibit NEC-UW_03, and of the Prefiled Rebuttal Testimony of Ulrich Witte Regarding New England Coalition, Inc.'s Contentions 2A, 2B and 4 that discuss Entergy's alleged reduction of the number of FAC inspection data points between the 2005 refueling outage and the 2006 refueling outage. The specific discussion NEC moves to withdraw is indicated on the copies of Mr. Witte's testimony and report attached hereto as Attachments B-D.

In the process of responding to Motions in Limine to exclude his report, Exhibit NEC-UW_03, Mr. Witte determined that his discussion of the alleged reduction in FAC inspection data points was based on a corrupted version of the document filed as Exhibit

[1] Mr. Witte converted this document to a text-searchable format from a PDF file. The conversion changed the substance of some of the text. The corrected version of this Exhibit is printed from the PDF file Entergy produced to NEC.

NEC-UW_20. Mr. Witte converted this document to a text-searchable format from a PDF-format file. The conversion altered some of the text of the document, including the number of 2005 inspection data points. Page NEC037118 of the converted document states that the 2005 RFO inspection scope consisted of "0137 large bore components." The PDF-format copy of this document that Entergy produced to NEC states that 37 components were inspected.

III. Consultation

NEC has consulted or attempted to consult with all parties concerning these motions. The NRC Staff is not opposed. Entergy could not take a position without reviewing NEC's filing. The State of Vermont is not opposed to the filing of these motions, but reserves the right to comment on their substance. The States of Massachusetts and New Hampshire did not take a position.

June 27, 2008 New England Coalition, Inc.

by: Karen Tyler

Andrew Raubvogel
Karen Tyler
SHEMS DUNKIEL KASSEL & SAUNDERS PLLC
For the firm

Attorneys for NEC

ATTACHMENT A

NEC-UW_03
CORRECTED

REDACTED

EVALUATION OF VERMONT YANKEE NUCLEAR POWER STATION LICENSE EXTENSION: PROPOSED AGING MANAGEMENT PROGRAM FOR FLOW ACCELERATED CORROSION

I. Introduction

I submit the following comments in support of the New England Coalition, Inc.'s ("NEC") Contention 4. My comments concern the Applicant's aging management program, specifically addressing the fidelity of the Flow-Accelerated Corrosion ("FAC") Program (NEC Contention 4).

NEC asserts that the application for License Renewal submitted by Entergy for Vermont Yankee does not include an adequate plan to monitor and manage aging of plant equipment due to flow-accelerated corrosion ("FAC") during extended plant operation. The Applicant has represented that its FAC management program during the period of extended operation will be the same as its program under the current operating license, and consistent with industry guidance, including EPRI NSAC 202L R.3. The use of the CHECWORKS model is a central element in the Program implementation.

In the Applicant's motion for summary disposition, the Applicant proffered a response that credits the its current program for FAC management at the facility, and simply extends the current program for the renewal period, making the following statement: "furthermore, the FAC program that will be implemented by Entergy is the same program being carried out today, which has not been otherwise challenged by NEC, will meet all regulatory guidance." Ref. Entergy Motion for Summary Disposition on New England Coalition's Contention 4 (Flow Accelerated Corrosion), June 5, 2007, at 3. Italics added.

The Applicant has asserted that it is in full compliance with its current licensing basis regarding its FAC program. The Applicant asserts that the plans for monitoring flow accelerated corrosion, including the FAC Program goal of preclusion includes appropriate procedures or administrative controls to assure that the structural steel integrity of all steel lines containing high-energy fluids is maintained. *Id* at 6. The applicant is argues that since the VY FAC program is based on EPRI guidelines and has been in effect since 1990, one could therefore conclude the applicant has established methodology so as to preclude of negative design margin or forestall an actual pipe rupture, and Entergy infers that it is technically adequate and is compliant with its licensing basis requirements.

I draw a different conclusion. Based on the *implemented* program presently in place, and the historical inadequacies necessary for effective implementation (including evolution) of the FAC program, the oversights are substantial in program scope, application of modeling software, and finally necessary revisions to the program not implemented as was promised to support the power up-rate. I am not alone in this conclusion. Program weaknesses and failures have been identified by others and form the basis of condition reports, the categorization as *unsatisfactory* in a Quality Assurance Audit dated November 11, 2004[1], and noted as "yellow" in a cornerstone roll-up report circa 2006[2]. In addition, the NRC Project Manager made a recent inquiry into indications of an out-of-date program.[3] On Monday, April 21, 2008, I spoke by phone with NRC resident inspector Beth Sienel, and she confirmed that, even now, Entergy has not completed verification of the upgrade of the CHECWORKS model to EPU design conditions. This concern regarding deficiencies in implementation of the program brings

[1] Exhibit NEC-UW_9, Audit No.: QA-8-2004-VY-1, "Engineering Programs", page 2, (NEC038514).

[2] Exhibit NEC-UW_7, Cornerstone Rollup, Program: Flow Accelerated Corrosion, Quarter: 3rd, dated 10/03/2006, page NEC038424, Open Action Items, (includes All CR-CAs, ER post action items and LO-CAs, is shown as "yellow", however, 6 LO-CAs are shown as open. By definition, "Red" includes 2 or more CR-CAs and /or E/R post action items (excluding LOs action items) greater than one year.

[3] Exhibit NEC-UW_14.

into question the results of FAC inspection during RFO 25 and RFO 26, in which power up-rate design data apparently is as yet not incorporated.

These program implementation delays are substantive, and based upon the information provided to NEC appear to remain unresolved. These deficient conditions raise questions as to the fidelity of the entire license renewal application, Entergy's commitments for license renewal, management oversight, and the efficacy of the regulatory-required Corrective Action Program.

If it is true that power up-rate parameters such as flow velocity were not incorporated into the FAC program model, these deficiencies appear to be substantive and without question warrant condition reports under the Entergy Corrective Action Program, in particular given that they appear to violate regulatory commitments regarding the Flow Accelerated Corrosion Program.

10 CFR Part 50 Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," provides that a condition that is deficient is *required* to be identified, investigated, and remediated expeditiously.[4] Promises to correct the deficient program at some point in the future are not sufficient, unless all reasonable alternative methods for remediation are exhausted and the condition is shown to be safe in the interim. Lack of oversight and a *single missed inspection point* that remained unnoticed

[4] 10CFR Part 50, Appendix B, XVI, "Corrective Action," states: "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management."

for years[5] led the Japanese Mihama Plant FAC pipe rupture in 2004, causing five fatalities.[6] As discussed in detail below, Vermont Yankee missed dozens of points.

Identification of discrepancies and timely corrective action are the cornerstones of a well-managed plant. In my experience assisting problematic plants, change usually begins with a cultural shift toward proactive corrective action and away from a reactive mentality of delaying needed corrective actions to programs such as FAC that result in unresolved deficient conditions and unnecessarily narrowed safety margins for longer periods of time than are necessary.

A common metric used by the regulator (for example in ROP reviews) and management is the volume of the backlog of open corrective actions and the number of open corrective actions that date further back than one year, two years or even three or more years, to establish the fidelity of the licensee's compliance with the terms of its operating license and associated commitments. The metric is useful in evaluating Flow Accelerated Corrosion management at Vermont Yankee.

II. Summary Assessment

Based on a detailed review of the record provided to NEC regarding the Flow-Accelerated Corrosion Program, my conclusion is that the FAC program appears to have been in non-compliance with its licensing basis from about 1999 through February 2008. The failure to comply is evidenced by the licensee's own assessments, audits, and condition reports, roll-up of numerous cornerstone reports, and focused self-assessments. Corrective actions from approximately five Condition Reports ("CR") remained open for

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[5] Exhibit UW_20, Page 6 of 14 of VY FAC Inspection Program PP7028, 2005 refueling outage at NEC037109.

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[6] *Kepco Ordered to Shut Down Mihama Reactor.* The Japan Times, September 28, 2004, *available at http://search.japantimes.co.jp/member/member.html?nn20040928a6.htm.*

as much as four years. The last condition report regarding FAC, CR 2006-2699, was written on August 30, 2006. Although noted in the cornerstone report dated October of 2006[7], the condition report apparently was never provided to NEC. The condition report aggregated approximately six corrective actions to the program that had been ignored and the current status was then open and which is presently unknown to NEC.

In addition, the most recent FAC inspection was performed under superseded procedures and the results therefore are of potentially no programmatic value[8]. Procedure ENN-DC-315, was revised and in effect on March 1, 2006, yet superseded on December 1, 2006 by yet a new program level procedure. Close examination shows that the procedures prepared, approved and implemented by Entergy for implementing the FAC Program were substantially revised, yet were not used in the most recent flow-accelerated corrosion inspections after VY increased operating power by 20 percent in the March, 2006 EPU, nor were they available for RFO 25, the first outage after power up-rate. Required changes, including both a software upgrade and design parameters regarding the substantial plant modification to uprate the plant to 120% power, were not incorporated for either outage, and were in fact still being implemented in February 2008, when Staff inquired on this subject.

[7] Exhibit NEC-UW_07 Cornerstone Rollup, Program: Flow Accelerated Corrosion, Program Infrastructure Cornerstone, Quarter: 3rd, dated 10/03/2006, page NEC038419 ("Corrective Action Plan to complete open LO-CA tasks developed 10/02/2006, (CR-2006-02699)"). *See also* pp. NEC038422, NEC038424, NEC038426-28—see also footnote 3.

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[8] Exhibit NEC-JH_42, VY Piping FAC Inspection Program PP 7028- 2007 Refueling Outage, Inspection Location Worksheets/ Methods and Reasons for Component Selection," April 3, 2006, at 1, NEC017888.

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[redacted]. The Feedwater System FAC review was run using 1999 Ultrasonic Test ("UT") data, yet the results were not used in the RFO 24 outage.

To be an even marginally predictive modeling tool, the CHECWORKS model should have been kept current for successive outages, [redacted][10]) that were required to be managed for FAC as far back as 1999. The predictive capability of CHECWORKS was virtually non-existent for the period from 1999 forward. Although Entergy did incorporate the program, which depends heavily on trending of data of multiple outages, they incorporated in one plunge plant design conditions during the 3rd quarter 2006. The scoping document supporting selection of grid points collected essentially all the sins of the past, including, for example, stale predictive inspection data from the out-of-date version of CHECWORKS, and placed heavy reliance on engineering judgment. As provided under the 2005 scoping document[11],

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11 Exhibit NEC-UW_20, PP7028 Piping FAC Inspection Program, FAC Inspection Records for 2005 Refueling Outage, undated, NEC037099. Includes on page NEC037104, Inspection Locations and Reasons for component selection, dated 3/1/05. Note on page 2 of 14 of this report, exclusions of inspection scope were based upon cycle predictions from 1999, and did not appear to include Uprate design changes, nor account for the EPRI model not being current. Many recommendations from 1999 were not to reinspect until 2007—or 9 years. This approach appears to be entirely inconsistent with NSAC 202L. Newer examinations

the rationale for selection of grid points relied on (1) length of time since the lapsed inspections had ceased to examine a particular inspection point, (2) CHECWORKS User Groups, (CHUG) suspects found at other plants, (3) exclusion of components that were intended to be replaced based upon another regime or degraded condition.

Had data from previous FAC inspections routinely been entered into CHECWORKS, the selection of grid points and ranking would have provided a better historical perspective on where to inspect in successive outages, including the most recent outage. With the exception of VY's strength in reactively replacing piping or components with FAC-resistant material during repairs or maintenance, the program itself was not effective as a predictive modeling tool. Simply stated, once something ruptured or was found to be outside its design margin, it was replaced in a reactive management approach. Proactive management of the program to *predict failures* has been inadequate in the FAC Program, as referenced above.

Even the most recent inspection completed for RFO 26 appears to have been structured around procedures that were superseded, scoping requirements to establish a new baseline of pipe geometry and as-found wall thickness were based on stale data, and the upper-tiered governing procedure that was used had not been revised since 2001 and was therefore void.[12]

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showed an trend of increased frequency of reinspection . See NEC037106. Page 4 of 14 provides for negative margin, or no inspections for Feedwater System. Conclusions called for "assessing the need" for inspections in 2007 outage. See page NEC037107. The condensation system showed one component with negative time to Tmin. The Extraction Steam System indicated three components with negative time to code min wall. Page NEC037108.

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[12] Exhibit NEC-UW-11, Official Transcript of Proceedings ACRST-3397, Advisory Committee on Reactor Safeguards Subcommittee on Plant License Renewal, June 5, 2007, at page 43. Entergy's Mr. Dreyfuss stated: "...we did increase the number of FAC inspections by 50 percent from what we typically do in outages. We did 63 inspections overall." It is also noted that the average number of points examined by the domestic industry is 82—under a well managed program, without significant changes to the model—such as a power uprate.

The current program-level procedure had been in existence since March 2006. Scoping was performed in May of 2006 under the void procedure, and updating of CHECWORKS was not done until 3rd quarter 2006.[13] Grid points, scope selection, and small bore piping susceptibility do not appear to have been ranked under NSAC 202L guidance or in an orderly trending of data by CHECWORKS based upon repeated passes with new grid points and new rankings selected. Data input and passes by CHECWORKS were not accomplished on an outage-by-outage basis.[14]

With only 63 points examined in RFO 26[15], the baseline for the power up-rate conditions appears not to have been established. I found it troubling that RFO 26 results were provided to the Advisory Committee on Reactor Safeguards ("ACRS") on June 5, 2007, but apparently were not disclosed to NEC.

VY is the first plant modified to achieve Constant Pressure Power Up-rate to 120% power and only one other plant out of the fleet of 104 was licensed to 120% increase in power in one step. Given the uniqueness of the design of VY's power up-rate, CHECWORKS has little industry benchmarking data, and is of marginal use.

The history of the one other up-rated power plant, Clinton Power Station, suggests the possibility of future problems at Vermont Yankee. The NRC inspected Clinton Power Station, including a review of the FAC program, after its up-rate in January 2003 and found the program to comply with its licensing basis, including NSAC 202L and the use

[13] Exhibit NEC-UW_07 at NEC038424.

[14] Exhibit NEC-UW-20, VY Piping FAC Inspection Program PP 7028- 2005 FAC Inspection Program Records for 2005 Refueling Outage at NEC037112 –NEC037120.

[15] Exhibit NEC-UW-11, Official Transcript of Proceedings ACRST-3397, Advisory Committee on Reactor Safeguards Subcommittee on Plant License Renewal, June 5, 2007, at page 43. Entergy's Mr. Dreyfuss stated: "...we did increase the number of FAC inspections by 50 percent from what we typically do in outages. We did 63 inspections overall." It is also noted that the average number of points examined by the domestic industry is 82—under a well managed program, without significant changes to the model—such as a power uprate.

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of CHECWORKS. Program inputs were fully incorporated from previous inspection data and heat balance up-rate data. Wear rates were predicted to increase 8% because of up-rated power conditions. Although the increase was a concern to the regulator, the program was found to be adequate. Yet only nine months later, Clinton experienced a FAC rupture[16]. It is relevant that this failure occurred approximately 16 years after Clinton received its operating license in 1987—while apparently complying with its CLB and the EPRI guidance.[17]

Plant Surry, where a rupture due to FAC killed four people, failed after 15 years of operation, and required 190 component replacements due to FAC. The accident led to unpredicted causal events outside the engineering design basis—including discharge of CO_2, seepage of the heavier than air gas into the control room, requiring reactor operators to don Scott air packs and with some operators exhibiting symptoms such as dizziness because of control room habitability[18]. Pleasant Prairie, a fossil plant with similar conditions, endured a catastrophic FAC failure at 13 years, causing two fatalities[19], and a Japanese plant failed without warning, killing five people, simply because of a failure to inspect one component section due to an administrative oversight, repeatedly missed by program owners.[20] The oversight was never noticed during quality control or quality assurance reviews, or spotted by the system engineers responsible for FAC at the plant.

[16] Exhibit NEC_JH-42 at 7 (NEC017894).

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[17] Exhibit NEC_UW-04; Exhibit NEC_UW-05 at §XI.M17.

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[18] Exhibit NEC-UW_22 U.S. NRC NUREG 0933; Issue 139: thinning of Carbon Steel Piping in LWRs (Rev. 1) at 1-4.

[19] Exhibit NEC_UW-21, Milwaukee Sentinel, March 9, 1995.

[20] Exhibit NEC_UW-20 at NEC037109.

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These plants were not specifically using aging management tools, where as others, such as Clinton, did—but each FAC failure occurred well before the plants reached their engineered end-of-life of 40 years. The event at Mihama occurred due to nothing more than an administrative failure to routinely inspect a known FAC-susceptible component.

I fully concur with NEC's consultant Dr. Joram Hopenfeld that comprehensive benchmarking will be required through the number of years when unmanaged FAC failures typically begin to emerge, such as the operational age of the Surry plant at the time of FAC failure, or the Clinton Plant failure.

III. Licensing basis for management of flow-accelerated corrosion at VY and review of the program implementation

I reviewed the FAC program in four parts: Part A, examining the current licensing basis; Part B, the *implementation* of the licensing basis; Part C, the Licensee's *own record* of problems with implementation; Part D, *my independent observations* based on the record provided to NEC, and the requirements for implementing an effective program under NRC-endorsed guidance, with which the Licensee has stated that it has complied.

A. The current licensing Basis and the proposed licensing basis for the flow accelerated corrosion program:

My review to establish the current licensing basis and the current status of application for license renewal includes the following documents:

1. NUREG 1801 Rev 1, §XI-M17, Flow Accelerated Corrosion

[redacted]

[redacted]

3. CHECWORKS EPRI procedures provided by the Applicant, including fleet procedure *EN-DC-315, Rev. 0, "Flow-Accelerated Corrosion Program" effective* December 1, 2006.

4. Commitments made by the licensee including the following:[22]

    i. USNR generic letter 89-08, Erosion corrosion –induced pipe wall thinning;
    ii. Vermont Yankee Letter to USNRC;
    iii. Vermont Yankee letter to the USNRC, Vermont Yankee Response to NRC Bulletin No. 87-01: Thinning of Pipe Walls in Nuclear Power Plants, dated September 11, 1987;
    iv. Vermont Yankee letter to the USNRC, Supplement to Vermont Yankee Response to NRC Bulletin No. 87-01: Thinning of Pipe Walls in Nuclear Power Plants, dated December 24, 1987;
    v. USNRC Generic Letter 90-05, Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2 and 3 Piping, dated June 15, 1990;
    vi. Vermont Yankee letter to the USNRC, request from code relief for use of ASME Code Case N-597, as an alternative to analytical evaluation of wall thinning;
    vii. USNRC letter to Vermont Yankee, Vermont Yankee Nuclear Power Station—Relief request for use of ASME code case N-597 as an Alternative Analytical Evaluation of wall thinning (TAC No. MB1530) dated July 27, 2001. NVY 01-74;
    viii. VY memo: J.F Calchera to OEC (R. McCullough), subject: response to commitment item: ER-990876_01, Reevaluate Feedwater Heater Inspection Program to address Ownership, dated April 25, 2000.

Industry guidance and other records that were used for interpreting VY position regarding license renewal include:

    ix. Flow accelerated corrosion in power plants TR-106611-R1, published by EPRI in 1999;
    x. Official Transcript Advisory Committee on Reactor Safeguards subcommittee on Power Uprates November 30, 2005;
    xi. RAI SPLB-A-1 (LR001576);
    xii. Section 12-2 Wear rate analysis (Excerpt from an EPRI report);

[22] Items i., ii, iii, iv, and viii listed as commitments were not provided to NEC but were only referenced in Entergy's program level documents, and therefore were not directly reviewed. They do not appear on Entergy's Appendix A, licensee renewal list of commitments, but are listed in program level documents that were valid until March 15, 2006. No evidence of withdrawal, modification, or otherwise changes to these commitments was provided to NEC.

xiii. VYNPS License renewal Project Aging Management Program Evaluation Results. (NEC00113191)

B. Implementation of the Flow Accelerated Program in accordance with the CLB.

I reviewed the following documents to ensure the implementation of the FAC program in accordance with the CLB:

xiv. ENN-DC-315, Rev. 1, "Flow Accelerated Program;"
xv. VY-PP7028, Piping Flow Accelerated Corrosion Inspection Program;
xvi. VY –PP7028, FAC Inspection program PP 7028- 2007 Refueling outage;
xvii. VY -PP7028, piping inspection program, FAC inspection records for 2005 refueling outage;
xviii. ENN-CS-S-008, rev 0, effective 9/28/2005, pipe wall thinning structural evaluation;

xix. DP-0072.

C. Review of Inspection Histories, EPRI Reviews, Quality Assurance Reports, Cornerstone Roll-ups, Focused Self assessments, Condition Reports, and Independent Assessments, and NRC Inspection Reports.

In addition, I reviewed inspection histories, condition reports, quality assurance reports, and one cornerstone report rollup on trending in the FAC Program (2003)- through October, 2006), NRC Inspections, and various revisions to VYLRP subsections and revisions. The list included the following:

xx. Focused Self Assessment Report, Vermont Yankee Piping Flow Accelerated Corrosion inspection report, Condition Report LO-VTYLO-2003-0327;
xxi. Audit No. QA-8-2004-VY1, Engineering Programs, dated 11/22/2004;
xxii. EPRI review of Vermont Yankee Nuclear Power Flow-accelerated corrosion, dated February 28, 2000;
xxiii. CR –VTY-2005-02239;
xxiv. Cornerstone Rollup update last dated 10/23/2006;

xxv. VYNPS License Renewal Project Aging management Program Evaluation Results.23

D. **Current status of the FAC Program with respect to the licensing basis.**

1. The current licensing basis goal is to preclude negative design margin or pipe rupture due to Flow-Accelerated Corrosion and is centered around use of EPRI document NSAC 202L. The guidance is specifically endorsed by the NRC under NUREG 1801, which calls for a three prong approach to minimize uncertainties:

(1) Use of a model such as CHECWORKS [with precision in data collection, examination, and frequency];

(2) Use of sound engineering judgment in selecting inspection points that are independent of CHECWORKS; and

(3) Use of industry events that have potential relevance to VY in material condition, design parameters, and operating history.

There are numerous FAC-related failures throughout the industry. Examination of the OECD Pipe Failure Data Exchange Project (OPDE) database provides that information.[24]

2. To accomplish the licensing basis goal, the FAC Program needs explicitly to include each of the following ten elements under the specific Generic Aging Lessons Learned (GALL) Report:

1. Scope
2. Preventative actions
3. Parameters monitored or inspected

[23] These documents were typically provided to NEC in fragments, with no title page, no document date, no record of whether the documents were current and had superseded others, and no signature or references to the author.

[24] Exhibit NEC-UW_15, NucE 597D-Project 1, Data Collection of Pipe Failures occurring in Stainless Steel and Carbon Steel Piping. provides industry wide data on FAC failure. Page 20 includes a failure rate for BWR plants. The probabilistic risk assessment for BWR plant FAC failures is reported as 10E-5 (higher than reactor accident threshold PRA for Design Basis Accidents).

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4. Detection of aging effects

5. Trending

6. Acceptance criteria

7. Corrective actions

8. Confirmation processes

9. Administrative processes

10. Operating experience[25]

3. Implementation of these ten elements is accomplished under formal program-level procedures. Successful implementation requires actions in sequence that are constructive to yielding the highest predictability of wall thinning and the most certainty in ranking test points for inspection on a routine that collects wear data in a timely fashion, then adjusts the selection scope based upon multiple trending of data, along with incorporation of changes to the plant.[26]

4. [redacted].[27] The record indicates that the Vermont Yankee Nuclear Power Station ("VYNPS") FAC program only partially implemented its licensing basis requirements to achieve a successful FAC program and that Entergy was aware of the problematic state of the program for many years.[28]

[25] Exhibit NEC-UW_06 at 152-157; Exhibit NEC-UW_08 at 2.

[26] Exhibit NEC-UW_15 at 20. This Exhibit provides industry-wide data on FAC failures. The high rate of failure in BWR plants underscores the need for precision in implementing an FAC program.

[27] Exhibit NEC-JH_38 at 3-3, 4-1.

[28] Exhibits NEC-JH-42 at NEC017893-912; Exhibit NEC-UW-09 at NEC038514, NEC038515, NEC038529, NEC038531-038533; Exhibit NEC-UW_07 at NEC038422.

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5. The self-identified deficiencies in Entergy's current VYNPS FAC Program are identified in multiple documents. [redacted][29] Entergy apparently ignored the warning. More troubling is that Entergy continued to be in non-compliance with its licensing basis through the years 1999-2006. This deficiency was again noted in late 2004 under an internal quality assurance audit, and two Condition Reports were written.[30]

6. Relevant data apparently was not entered into the CHECWORKS model until the third quarter of 2006.[31] The October 23, 2006 rollup thus confirms that the model was not kept current during a seven-year period and suggests that susceptible locations may not have been inspected during this time period. This lengthy lapse significantly weakened the trending capability of the software, both during the lapse period and presently. It is also evident that EPU data was still being modeled and validated in 2008.[32] [redacted]

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[29] Exhibit NEC-UW-08 at 1, 4-6.

[30] Exhibit NEC-UW-09 at 2, NEC038531-NEC038555, "CR-VTY-2004-03062" and "CR-VTY-2004-03061."

[31] Exhibit NEC-UW-07 at NEC038424 ("CHECWORKS models and wear data analysis updated with all previous inspections in 3rd quarter 2006.").

[32] Exhibit NEC-UW_14, Email from Beth Sienel to Jonathan Rowley, Feburary 20, 2008.

[33] [redacted]

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[redacted][34]

In spite of Entergy's commitment, the required additional susceptibility scoping analysis is not apparent to NEC in information provided.

7. From 1999-2006, the plant was essentially operating in a state in which component wear was improperly trended and pipe conditions were actually unknown. Reliance on CHECWORKS for this time period for predicting grid points, ranking susceptible components, and inspecting new points was therefore virtually without technical or empirical value. Without proper trending, the predictability goal of CHECWORKS is lost; it essentially became a data collection repository.

8. During the years 2000-2006, the VYNPS FAC program apparently used an outdated version of the CHECWORKS software. [redacted] Entergy's failure to

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[34] [redacted].

[35] Exhibit NEC-UW-08 at 5-6; NEC-UW-20 at NEC037103.

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update the CHECWORKS model in a timely fashion makes data comparison between operating cycles more difficult.

9. In 2004, at least four VYNPS components, including the condensate system and the extraction steam systems, were determined to have "negative time to Tmin," meaning that wall thinning was being predicted as beyond operability limits and should be considered unsafe with potential rupture at anytime.[36] "Negative cycles of operations," meaning wall thinning *beyond* acceptable code limits, were also predicted. The hours negative to the next inspection were substantial—predicting potential code violation or failure could have occurred 3000+ hours previously to October 23, 2006. It is surprising that the Licensee apparently did not write condition reports for this condition. I do not believe that NEC received any notice of Condition Reports relevant to this significant indication by CHECWORKS predicting substantial wall thinning beyond code limits to occur with negative margin of this magnitude. This issue is particularly troubling given that the equipment failure event is unpredictable, and catastrophic when wall thinning is beyond acceptable limits. Despite CHECWORKS' prediction of wall thinning, the plant continued to operate., I have not seen any inspection or audit discussion of this situation. It does, however, appear on the RFO 24 Inspection Plan,[37] oddly with the same number of hours of negative time to Tmin, even with the plan including wear data observed of 30% increase at Quad Cities and Dresden after the up-rate.[38]

[36] Exhibit NEC-JH_42 at NEC017893. *See also* NEC-UW-20 at NEC037108.

[37] Exhibit NEC-JH_43 at NEC020189.

[38] Id. at NEC020197.

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10. The VYNPS FAC program was deemed unsatisfactory under quality assurance review dated November 22, 2004, and two condition reports were written.[39] On page 5, the report notes the need for program management to ensure update of susceptible piping to be identified and modifications to be incorporated.[40] In addition, the report notes that cross-discipline review required by procedure had not been performed.[41]

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11. The 2006 cornerstone report shows a number of indicators as yellow, with lists of open CR corrective actions, and a new CR written in August 30, 2006.[42] The report lists six corrective actions and four CRs that were written as early as 2003 that remain open.[43] These include references to a number of progress indicators, but authors of the report continue to express concern over the program and the slow progress to update the CHECWORKS model. I reviewed several of the listed condition reports, some more than four years old, and found no indication that corrective actions recommended in these reports were completed.

12. In addition, in 2005 a sixth CR was written, CR-VTY-2005-02239, stating "CHECWORKS predictive model for Piping FAC inspection program was not updated per appendix D of PP7028."[44] The first page of the CR includes a statement that this condition had no impact on the RFO 25 inspection scope – i.e., indicating that updating of CHECWORKS was not necessary for establishing scope of RFO 25. This assertion is

[39] Exhibit NEC-UW-09 at 2 (NEC038514).

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[40] Exhibit NEC-UW-09 at 5 (NEC038517).

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[41] Id.

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[42] Exhibit NEC-UW-07 at NEC038419, NEC038422.

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[43] Exhibit NEC-UW-07 at NEC038424.

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[44] Exhibit NEC-UW-10 at 1.

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another indicator that the VY FAC program was *prima facie* in noncompliance with its CLB.

13. A review of a focused self-assessment was performed. This assessment was called for under one corrective action from a condition report LO-VTYLO-2003-00327. The report identifies numerous issues that required or require action to bring the FAC program into compliance with the CLB. For example, the program susceptibility review report for 2004 was not formal, and did not properly separate scope for ranking.[45] The report was not given an adequate review, nor placed in the document control system.

14. PP7028 notes plant modifications and inspection results as not updated since May 15, 2000.[46]

15. Ranking of small-bore piping was not done. With no ranking, the basis for selection of high susceptibility points for small-bore piping is not evident.[47] Procedural conflicts were identified with missing programmatic requirements.[48]

16. A flow-accelerated corrosion related pipe break associated with a 1" elbow, SSH (WO 06-6880), appears to have occurred in 3rd quarter 2006.[49]

17. Entergy apparently reduced the number of FAC inspection data points between the 2005 refueling outage and the 2006 refueling outage, in violation of its commitment to *increase* inspection data points by 50%. The 2005 refueling outage inspection called for

[45] Exhibit NEC-JH_44 at 17.
[46] Id. at 18.
[47] Id. at 19.
[48] Id. at 27-29.
[49] Exhibit NEC-UW-07 at NEC038428.

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137 large-bore inspection points. The 2006 refueling outage inspection, presented to the ACRS on June 5, 2007, covered only 63 points.[50]

18. The 2006 refueling outage FAC inspection scope, planning, documentation, and procedural analysis all appear to have been performed under a superseded program document. ENN-DC-315 Rev.1 was effective March 15, 2006, superseding the PP7028 Piping FAC Inspection Program.[51] Yet VY inspection plan for FAC Program PP7028 was approved on May 11, 2006, almost two months after the PP7028 program document was superseded.[52] This error potentially invalidates the baseline requirement of CHECWORKS, in accordance with NRC-endorsed guidance, to establish the as-found condition of components and piping.[53] The fundamental step of updating inputs is required in the NSAC 202L approach for FAC, and is a required step in the CHECWORKS instructions. Essentially, working to a void procedure makes the results invalid [redacted] Given the significant changes to the plant, a baseline pass with accurate inputs was necessary, and subsequent passes were necessary to establish the grid locations and high susceptibility inspection points.

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[50] Exhibit NEC-UW-11 at 43.

[51] Exhibit NEC-UW-12 (ENN-DC-315) at 1; Exhibit NEC-UW_19 (PP7028).

[52] Exhibit NEC-JH-42 at NEC017888.

[53] Exhibit NEC-UW-06 at § XI.M17.

[54] Exhibit NEC-JH-38 at 4-5.

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19. No indication is provided that plant isometrics were updated as required as of 10/22/04.[55]

IV. Time needed to benchmark CHECWORKS for Post-EPU use at VYNPS

I agree with the testimony of Dr. Joram Hopenfeld that CHECWORKS is an empirical model that must be updated with plant-specific data. NUREG 1801 does not specify the number of years' data necessary to benchmark CHECWORKS, but does advise that a baseline must be established as noted above [redacted] This requirement is reasonable given that each plant has unique characteristics and operating history. Separate industry guidance supports five to ten years of data trending.[57] Trending to the high end of the range is appropriate where variables affecting wear rate, such as flow velocity, have significantly changed, as at VYNPS following the 120% power up-rate.

Given the deficiencies in the current VYNPS FAC program discussed in this statement, trending under the program is of marginal value. In addition, substantial "negative margin" conditions were identified in scoping the 2005 FAC inspection—many of which were predicted because of the repeated missed inspections in previous outages (that, significantly, occurred prior to up-rate).

[55] *Exhibit* NEC-JH_44 at 19.

[56] [redacted]

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[57] Exhibit NEC-UW-13 at 38 ("In order to establish a baseline for the plant's equipment performance and reliability, the operating history over the past 5 to 10 years is reviewed and trended.").

I do not agree that a prolonged period of data collection is not necessary to use CHECWORKS effectively at VYNPS after the 120% power up-rate because the predictive algorithms built into CHECWORKS are based on FAC data from many plants. VYNPS is unique in its approach of Constant Pressure Power Up-rate to 120%. Clinton is the only other plant to accomplish a one-step up-rate to 120% power and is a very different plant from VY. To my knowledge, out of 104 operating plants only six have increased operating power by more than 15%.[58] Of this group, at least three – Clinton, Dresden, and Quad Cities – appear to have FAC-related issues.[59] The argument that CHECWORKS incorporates relevant industry data is difficult to accept when so few plants are operating under analogous conditions, and 50% of those have experienced FAC related problems.

The need to extend the period of data collection is further evidenced by the fact that the CHECWORKS model was not updated with plant-specific changes until after RFO 26. Furthermore, by inference from an inquiry by the Staff project manager to the resident inspectors office only two months ago, it appears the NRC was informed that the EPU up-rate conditions *were still being verified and the process was at this late date incomplete after two outages had passed* since EPU design was completed, licensed, and implemented. The apparent failure to update the program underscores the lack of benchmarking done to date regarding the CHECWORKS software, and demonstrates troubling failures by Entergy to adhere to their own procedural requirements and failure to honor commitments made to the regulator, for example, made to the ACRS in November

[58] Exhibit NEC-UW_18, Union of Concerned Scientists, "Power Uprate History," July 12, 2007.

[59] Exhibit NEC-UW_20 at NEC037109, NEC037116; JH_42 at NEC017894, NEC017897, NEC017898; JH_43 at NEC020196.

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2005, regarding use of the tool and the applicant's intention to conduct benchmarking testing during RFO 25 and RFO 26.

Based on the foregoing, it is my opinion that seven or more cycles will be necessary to establish a credible benchmarking of CHECWORKS to VYNPS under up-rated operating conditions [redacted] It is also my opinion that benchmarking can only be accomplished after the current program deficiencies are corrected and a proper baseline is established.

[60] Exhibit NEC-UW-08, [Proprietary] [redacted]

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Dr. Brian W. Sheron
Associate Director for Project Licensing and Technical Analysis
U.S. Nuclear Regulatory Commission
MS 05E7
11555 Rockville Pike
Rockville, MD 20852-2738

Dear Dr. Sharon:

Enclosed are the results of a project given to my Penn State Graduate Students on finding pipe failure data over a range of pipe sizes and conditions. We specifically looked for stainless steel data as well as carbon steel pipe data. Since the data is from several sources other than nuclear the pipe wall thickness may not always be comparable to reactor pipe wall thicknesses. In some of the reports the students did separate the failure and leakage data by mechanism such that we could then screen the data.

I had the students normalize the data in such a fashion that we could then compare to the break frequency spectrum curves generated by the NRC experts group. I did talk to Rob Tenoning on the best way of normalizing our data such that we would be consistent with the break frequency plots. The key findings from the students work is that the data, when plotted in the same manner as the break frequency spectrum plots from the NRC experts work, shows a much flatter behavior at the larger pipe sizes indicating a more similar probability level for failure as compared to a more significant decrease in the failure probability as given by the NRC break frequency spectrum.

I am complying all the independent sets of data in a spread sheet and will attempt a further screening. Once complete, I will send you a copy of the data. I wanted you to have these report now with all the data so you could make an independent assessment.

Please let me know if you need anything else.

Very truly yours,

L.E. Hochreiter
Professor of Nuclear and Mechanical Engineering

NucE 597D - Project 1

DATA COLLECTION OF PIPE FAILURES OCCURING IN STAINLESS STEEL AND CARBON STEEL PIPING

Pennsylvania State University
Dr. L.E. Hochreiter
April 2005

Executive Summary

Currently the Nuclear Regulatory Commission (NRC) is contemplating changing the acceptance criteria for Emergency Core Cooling Systems (ECCS) for light-water nuclear power reactors contained in NRC Regulation 10 CFR 50.46. This regulation sets specific numerical acceptance criteria for peak cladding temperature, clad oxidation, total hydrogen generation, and core cooling under loss-of-coolant accident (LOCA) situations. Furthermore, the regulation requires that a spectrum of break sizes and locations be analyzed to determine the most severe case and to ensure the plant design can meet the acceptance criteria under such conditions.

Currently the regulation states that breaks of pipes in the reactor coolant pressure boundary up to, and including, a break equivalent in size to the double-ended rupture of the largest pipe in the reactor coolant system must be considered. While this restricts the design, it maintains a large safety margin ensuring the plant is covered under all LOCA situations. However, an impetus for change has resulted from materials research, analysis, and experience that indicate that the catastrophic rupture of a limiting size pipe at a nuclear power plant is a very low probability event.

If approved, the proposed change would divide the break spectrum into two categories based upon the likelihood of a break. Breaks of higher likelihood, breaks smaller than 10 inches, would need to meet the current requirements set forth in 10 CFR 50.46. Breaks of a lower likelihood, those larger than 10 inches, would only need to meet the requirements of maintaining a coolable geometry and having the capability for long term cooling.

The purpose of this project was to collect data on instances of pipe failures including cracks, leaks, and ruptures. For each instance of failure the plant type, pipe diameter, type of pipe, failure mechanism, and type of failure was recorded. The data was then collapsed based on plant type (PWR or BWR), type of pipe (carbon or stainless steel), pipe size, and failure mechanism. Then, normalized failure frequencies were calculated as a function of both pipe size and failure mechanism per reactor year. Plots of the frequency distributions were generated on a semi-log scale, and the frequency distributions as a function of pipe size were compared to the NRC predicted failure frequencies.

For this project our group collected two, independent sets of data. The first set was provided by the OECD Pipe Failure Data Exchange Project (OPDE), with a total of 2891 data points. The second set consists of 67 data points collected by our group from various sources. The two sets of data were not combined due to the lack of information accompanying the data presented in the OPDE database, such as plant name or exact failure size. This made it impossible to identify overlapping coverage and combine the information. Rather, within this report we have analyzed each data set individually in order to make an overall comparison of the trends observed for each data set and the NRC predictions.

The results from both the OPDE and the independent sets of data detailed in this report do not support the NRC's assertion that larger sized pipes do not break frequently enough to be used as design criteria. The overall trends of both sets of data show that the frequency of failures does not decrease as sharply with increasing pipe size as the NRC predicts.

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1.0 Detailed Introduction of Problem

In order to ensure the safety of nuclear plants the cooling performance of the Emergency Core Cooling System (ECCS) must be calculated in accordance with an acceptable evaluation model, and must be calculated for a number of postulated loss-of-coolant accidents (LOCA) resulting from pipe breaks of different sizes, locations, and other properties. This is done to provide sufficient assurance that a plant can handle even the most severe postulated LOCA. LOCA's are hypothetical accidents that would result from the loss of reactor coolant, at a rate in excess of the capability of the reactor coolant makeup system. Currently, the evaluation criteria for these types of accidents state that pipe breaks in the reactor coolant pressure boundary up to and including a break equivalent in size to the double-ended rupture of the largest pipe in the reactor coolant system must be considered. In the case of such an event the NRC has set forth the following criteria that must be met for a design to be considered acceptable [37]:

a. Peak cladding temperature must not exceed 2200° F.

b. Maximum cladding oxidation must not exceed 0.17 times the total cladding thickness before oxidation.

c. Maximum hydrogen generation. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

d. A coolable geometry of the core must be maintained.

e. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

While requiring that all plants be analyzed in the case of a double-ended guillotine break of the largest pipe restricts the design, it does maintain a large safety margin ensuring the plant is covered in all pipe break situations. However, an impetus for change has resulted from materials research, analysis, and experience which indicate that the catastrophic rupture of a large pipe at a nuclear power plant is a very low probability event. The hypothesis that is currently being set forth is that small pipes break more frequently than large pipes. The criteria would change so that the NRC would refocus their analysis efforts because they want to make sure that the appropriate amount of time and money are being invested in the areas of most concern.

Furthermore, risk analyses indicate that large break LOCA's are not significant contributors to plant risk. According to a presentation given by Dr. Brian Sheron of the NRC at Penn State in the Fall 2004, "using the double ended break of the largest pipe in the reactor coolant system as the design basis for the plant results in ECCS equipment requirements which are inconsistent with risk insights and places an unwarranted emphasis and resource expenditure on low risk contributors. This also places constraints on operations which are unnecessary from a public health and safety perspective." Therefore, the proposed rule change would use the pipe size with the largest break frequency as the design basis for pipe rupture and accident analysis of the plant. A pipe size with a 10 inch diameter is currently being suggested. [37]

The proposed change would divide the break spectrum into two categories based upon the likelihood of a break. Breaks of higher likelihood, or those smaller than 10 inches, would need to meet the current requirements set forth in 10 CFR 50.46. These include criteria (a) through (e) above. On the other hand, breaks of a lower likelihood, or those larger than 10 inches up to and including a double-ended guillotine break of the largest pipe in the reactor coolant system, would only need to meet the requirements of maintaining a coolable geometry and having the capability for long term cooling. Thus, criteria (a), (b), and (c) would be eliminated for these cases. [37]

The purpose of this project was to collect data on instances of pipe breaks, leaks, and cracking. These failures included pipe failures from broken pipes either by splits, ruptures, or guillotines, and cracks in pipes, either circumferential or length wise. For each instance found the plant type, pipe diameter, type of pipe, failure mechanism, and type of failure was recorded. Only stainless steel and carbon steel pipes were considered. Then, normalized failure frequency distributions were developed and compared to NRC predictions.

The predicted NRC failure frequencies were taken from Table 3 on page 14 of 10 CFR 50.46, LOCA Frequency Development [38]. This table is replicated below.

Table 1-1. NRC Total Preliminary BWR and PWR Frequencies.

Plant Type	Effective Break Size (inches)	Current Day Estimates (per cal. yr)			
		5%	Median	Mean	95%
BWR	1/2	3.0E-05	2.2E-04	4.7E-04	1.7E-03
	1 7/8	2.2E-06	4.3E-05	1.3E-04	5.0E-04
	3 1/4	2.7E-07	5.7E-06	2.4E-05	9.4E-05
	7	6.6E-08	1.4E-06	6.0E-06	2.3E-05
	18	1.5E-08	1.1E-07	2.2E-06	6.3E-06
	41	3.5E-11	8.5E-10	2.3E-06	8.6E-09
PWR	1/2	7.3E-04	3.7E-03	6.3E-03	2.0E-02
	1 7/8	6.9E-06	9.9E-05	2.3E-04	8.5E-04
	3 1/4	1.6E-07	4.9E-06	1.6E-05	6.2E-05
	7	1.1E-08	6.3E-07	2.3E-06	8.8E-06
	18	5.7E-10	7.5E-09	3.9E-08	1.5E-07
	41	4.2E-11	1.4E-09	2.3E-08	7.0E-08

2.0 Data Collected

For this project our group collected two, independent sets of data. The first set was provided by the OECD Pipe Failure Data Exchange Project (OPDE), with a total of 2891 data points. The second set consists of 67 data points collected by our group from various sources listed as references in this report. The two sets of data were not combined due to the lack of information accompanying the data presented in the OPDE database, such as plant name and exact failure size, which made identifying overlapping coverage impossible. Rather, within this report each data set was individually analyzed in order to make an overall comparison of the trends observed for each data set and the NRC predictions.

OECD Pipe Failure Data Exchange Project [3]

OECD Pipe Failure Data Exchange Project (OPDE) was established in 2002 as an international forum for the exchange of pipe failure information. It is a 3-year project with participants from twelve countries, including Belgium, Canada, Czech Republic, Finland, France, Germany, Japan, Republic of Korea, Spain, Sweden, Switzerland and the United States. "The objective of OPDE is to establish a well structured, comprehensive database on pipe failure events and to make the database available to project member organizations that provide data." [3] The OPDE database evolved from what existed in the "SLAP database" at the end of 1998 [2].

OPDE covers piping in primary-side and secondary-side process systems, standby safety systems, auxiliary systems, containment systems, support systems and fire protection systems. Furthermore, ASME Code Class 1 through 3 and non-Code piping has been considered. At the end of 2003, the OPDE database included approximately 4,400 records on pipe failure. The database also includes an additional 450 records on water hammer events where the structural integrity of piping was challenged but did not fail.

Access to the actual OPDE database is restricted to organizations providing input data. However, a "OPDE-Light" version of the database will be made available later this year to non-member organizations contracted by a project member to perform work or which pipe failure data is needed. This version will not include proprietary data, such as the exact pipe diameter, where failure occurred, and preclude any plant identities or dates. Our group was fortunate enough to get a copy of this "light" version of the database for BWR and PWR pipe failures reported as of February 24, 2005. A total of 2891 failures (1536 for PWR plants and 1355 for BWR plants) were provided in this database, and considered for this project.

The database listed the plant type, reactor system, apparent cause of failure, pipe size group, number of total failures for each cause and pipe size group, and then a break down of the type of failure within the category. An excerpt from the OPDE-Light database has been provided for clarification in Table 2-1 on the following page. The database, in its entirety, has been included in Appendix A of this report.

However, there are a few problems with this database related to the purpose of this project. First, since the database did not provide the type of pipe (carbon or stainless) for each failure, a reasonable prediction of what type of pipe was involved in the failure based on the plant system, which was given, was made. The type of pipe assumed for each system is also given in the following page in Table 2-2.

Additionally, as previously mentioned, no explicit pipe diameters were given for each failure due to the proprietary nature of this information. Rather, the failures were collected into group sizes before it was sent out. A total of six group sizes were utilized by OPDE. The range of pipe diameters that comprise each group is given in Table 2-3. The main problem with these groupings, and the database in general, is that pipes larger than 10 inches in diameter are all grouped together and there is no way of determining how much larger than 10 inches they actually were. Finally, for the purpose of this analysis any crack, leak, or issue (i.e. wall thinning) with the pipe was considered to be a failure. However, the OPDE database lists the information by type of failure. The definitions of each failure type have been included in Table 2-4.

Independently Collected Data [5-36]

For the purpose of this project our group collected separate information on instances of piping failures and their causes. The information was collected primarily from Nuclear Regulatory Commission (NRC) bulletins, information notices, event reports, and generic letters. Our group was able to compile a total of 67 instances of piping failures. This database is provided in Appendix B. While our database is much smaller than the one compiled by the OECD Pipe Failure Exchange Project, it provides an independent check of the trends observed by that database.

A list of references is provided at the end of this report, and some of the actual references, printed from the NRC website, have been included in Appendix D.

Table 2-1. Excerpt from "OPDE-Light" Database

PLANT TYPE	PIPE TYPE	SYSTEM GROUP	APPARENT CAUSE	PIPE SIZE GROUP	TOTAL NO. OF RECORDS	Crack-Full	Crack-Part	Deformation	Large Leak	Leak	P/H-Leak	Rupture	Severance	Small Leak	Wall thinning
BWR	SS	RAS	Severe overloading	2	3			1				2			
BWR	SS	RCPB	external damage	3	1			1							
BWR	SS	RCPB	Severe Overloading	4	1			1							
BWR	SS	SIR	Severe overloading	6	1			1							
BWR	CS	STEAM	Water Hammer	6	1			1							
BWR	SS	RCPB	HF:Welding Error	3	7	1				1	1			4	
BWR	SS	RAS	TGSCC - Transgranular SCC	2	7	1	1				1			4	
BWR	SS	SIR	IGSCC - Intergranular SCC	4	4	1					2			1	
BWR	SS	RAS	IGSCC - Intergranular SCC	4	56	1	32				9		1	13	
BWR	SS	SIR		0	1	1									
BWR	SS	RCPB	TGSCC - Transgranular SCC	1	1	1									
BWR	SS	SIR	IGSCC - Intergranular SCC	2	3	1	1							1	
BWR	SS	RCPB	Overpressurization	4	2	1						1			
BWR	CS	AUXC	Vibration-Fatigue	5	1	1									

Table 2-2. Description of Plant Systems and Type of Piping.

Plant Group	Representative Plant System Names	Type of Piping
AUXC	Service Water Systems, Raw Water Cooling Systems	Carbon
CS	Containment Spray System	Stainless
EHC	Electro-Hydraulic Control System	Carbon
EPS	Emergency Diesel Generator System	Stainless
FPS	Fire Protection System	Carbon
FWC	Feedwater & Condensate Systems	Stainless
IA-SA	Instrument Air & Service Air Systems	Carbon
PCS	Power Conversion Systems (incl. Steam Extraction Lines, Heater Drain Lines, etc.)	Carbon
RAS	Reactor Auxiliary Systems (incl., CVCS, RWCU, CCWS, CRD)	Stainless
RCPB	Reactor Coolant Pressure Boundary	Stainless
SG	Steam Generator Systems (e.g., S/G Blowdown System)	Carbon
SIR	Safety Injection & Recirculation Systems	Stainless
STEAM	Main Steam (from nuclear boiler/steam generator up to turbine steam admission)	Carbon

Table 2-3. Definition of OPDE Pipe Size Groups.

Pipe Size Group	Corresponding Pipe Diameters (mm)	Corresponding Pipe Diameters (inches)
1	DN < 15	DN < 0.6
2	15 < DN < 25	0.6 < DN < 1.0
3	25 < DN < 50	1.0 < DN < 2.0
4	50 < DN < 100	2.0 < DN < 4.0
5	100 < DN < 250	4.0 < DN < 10.0
6	DN > 250	DN > 10.0

Table 2-4. OPDE Pipe Failure Definitions.

Type	Description
Crack - Part	Part through-wall crack (≥ 10% of wall thickness)
Crack - Full	Through-wall but no active leakage; leakage may be detected given a plant mode change involving cooldown and depressurization.
Wall Thinning	Internal pipe wall thinning due to flow accelerated corrosion - FAC
Small Leak	Leak rate within Technical Specification limits
Pinhole Leak	Differs from "small leak" only in terms of the geometry of the throughwall defect and the underlying degradation or damage mechanism
Large Leak	Leak rate in excess of Technical Specification limits but within the makeup capability of safety injection systems
Severance	Full circumferential crack – caused by external impact/force, including high-cycle mechanical fatigue – limited to small-diameter piping, typically
Rupture	Large flow rate and major, sudden loss of structural integrity. Invariably caused by influences of a degradation mechanism (e.g., FAC) in combination with a severe overload condition (e.g., water hammer)

3.0 Collapsing and Analyzing the Collected Data

The next important step in this analysis was collapsing the collected information into a usable form by specifying pipe size groups and failure mechanisms. The data was broken into separate bins based on plant type (PWR or BWR), pipe type (carbon or stainless), failure mechanism, and pipe size. Table 3-1 below lists the pipe diameters included in each bin for this analysis.

Table 3-1. Definition of Pipe Size Groups.

OPDE Pipe Size Groups	Corresponding Pipe Diameters (inches)
1+2	0.0-1.0
3	1.0-2.0
4	2.0-4.0
5	4.0-10.0
6	> 10.0

Note: This grouping of piping diameters includes one less bin than used by the OPDE database. Combination of the data from groups 1 and 2 of the OPDE database allowed the bin sizes to correspond more readily with those used by the NRC for listing predicted failure frequencies, taken from page 14 of 10 CFR 50.46, LOCA Frequency Development. The categories used for the NRC predicted failure frequencies are given in Table 3-2. [38]

Table 3-2. Definition of NRC LOCA Groups.

LOCA Category	Effective Break Size (inches)
1	1/2
2	1 7/8
3	3 1/4
4	7
5	18
6	41

It can be seen that for LOCA categories 1 though 5 the effective break sizes fall within the ranges listed for the pipe size groups, after pipe size groups 1 and 2 from the OPDE database were combined. LOCA category 6 was not considered in this analysis since the OPDE database did not provide specific information for pipes larger than 10 inches. The effect of this on the results will be discussed later in this report.

After collapsing the data based on pipe size, the data was then collapsed further by combining some of the failure mechanisms. The following is a list of the failure mechanisms that are used to group the data. Several items have been placed into general categories for simplification purposes.

1. Corrosion
2. Flow Accelerated Corrosion (FAC)
3. Microbiological Induced Corrosion (MIC)
4. Erosion
5. Fatigue
    a. Thermal Fatigue
    b. Vibration Fatigue
6. Human Factors (already combined in the OPDE database)
    a. Welding Error
    b. Fabrication Error
    c. Human Error
7. Mechanical Failures
    a. Excessive Vibration
    b. Overpressurization
    c. Overstressed
    d. Severe Overloading
8. Stress Corrosion Cracking
9. Water Hammer
10. Miscellaneous
    a. Brittle Fracture
    b. Cavitation
    c. External Damage
    d. Fretting
    e. Freezing
    f. Hot Cracking
    g. Hydrogen Embrittlement
    h. Unreported

After collapsing the data, it needed to be normalized so that failure frequency distributions could be calculated. Failure frequencies were calculated in for carbon steel pipes, stainless steel pipes, and a composite (both carbon and stainless) pipes as a function of both pipe group size and failure mechanism, separately for PWR and BWR plants.

The number of failures in each bin was normalized by dividing by the total number of failures. This gives the fraction of failures for each bin size. For example, when looking at carbon steel pipes in BWRs the number of failures in each pipe group size, regardless of failure mechanism, was divided by the total number of pipe failures (carbon + stainless) in BWRs. Similarly, the number of pipe failures in each failure mechanism bin, regardless of pipe size, was divided by the total number of pipe failures in BWRs.

Then, after normalizing the data, the fractional size in each bin was divided by 3390 calendar years of operation. This gives a failure frequency in 1/calander-years for each bin size. The number 3390 represents the number of reactor years experience in the US (2745 years) as of the end of 2003; divided by an assumed availability factor of 0.81 to get calendar years.

The normalization by pipe size (regardless of failure mechanism) and failure mechanism (regardless of pipe size) was repeated for BWR stainless steel failures, BWR composite failures, PWR carbon failures, PWR stainless steel failures, PWR composite failures, total carbon steel failures, total stainless steel failures, and total composite failures for a total of nine situations analyzed and a total of eighteen frequency distributions developed (nine as a function of pipe size and nine as a function of failure mechanism).

Finally, the frequency distributions developed were based both on pipe size and failure mechanisms for the different types of pipes had to be plotted against the NRC's predicted frequencies. Semi-log plots of failure frequency as a function of pipe group size were used.

OPDE Database

In order to use this database it had to be collapsed into a more useful form. First, after determining the type of pipe associated with each system, the plant system was no longer taken into consideration. Next, for the purpose of this project any type of failure (i.e. crack, rupture, wall thinning) was considered to be a pipe failure. Furthermore, as shown above several causes of failure were combined together into one failure mechanism category. The collapsed form of this database is provided in Appendix C.

Independent Database

There were 67 incidents recorded, which in the end did not provide enough data points in each bin to come up with a good normalized frequency distribution. When the data was sorted on plant type, then pipe material and finally on pipe size, various bins of pipe sizes had zero incidents. Appendix B is a listing of all of the incidents which were found. This listing is sorted on plant type, pipe material, and finally on pipe size. The highlighted incidents throughout the appendix represent incidents for which not enough information was given in the source to include this data in our analysis.

Failure mechanism plots were not made due to the lack of variety in failure mechanisms. The majority of the failure mechanisms were erosion/corrosion and stress corrosion cracking.

4.0 Results and Comparisons

4.1 Pipe Failures as a function of Pipe Size from OPDE Data

This section of the report examines the results of pipe failures as a function of pipe size. Normalized failure frequencies for carbon steel, stainless steel, and composite (carbon and stainless) pipes are presented individually for PWRs and BWRs. The NRC has developed their own failure frequencies for PWR and BWR plants as function of pipe size, but does not have separate frequencies for carbon and stainless steel pipes.

Table 4.1-1 lists the normalized failure frequencies for both PWR and BWR plants, regardless of pipe type, calculated from the OPDE database data and the NRC mean predictions [38].

Table 4.1-1. OPDE Calculated, and NRC Predicted, Normalized Failure Frequencies (1/cal-yrs).

Plant Type	Pipe Size Groups (inches)	OPDE Results	NRC Predictions
	0.0-1.0	1.3E-04	6.3E-03
	1.0-2.0	4.4E-05	2.3E-04
PWR	2.0-4.0	2.9E-05	1.6E-05
	4.0-10.0	4.6E-05	2.3E-06
	> 10.0	4.2E-05	3.9E-08
	0.0-1.0	8.2E-05	4.7E-04
	1.0-2.0	2.3E-05	1.3E-04
BWR	2.0-4.0	5.6E-05	2.4E-05
	4.0-10.0	6.2E-05	6.0E-06
	> 10.0	7.2E-05	2.2E-06

Figure 4.1-1 displays this information graphically on a semi-log plot with normalized failure frequencies on the y-axis and the pipe size groups on the x-axis. The figure shows that the results of the OPDE database underestimate the failure frequency for the smaller pipe size groups and overestimate the failure frequency for the larger pipe size groups compared to the NRC predictions for both PWRs and BWRs. However, there is less disparity in the two BWR predictions than the two PWR predictions.

The NRC predicts that PWR plants are much more likely to have pipe failures in smaller pipes than larger pipes. This trend remains the same in NRC prediction for BWR plants, but is not nearly as drastic. The OPDE results for both PWR and BWR plants show a much more consistent failure frequency both over the range of pipe sizes and between PWR and BWR plants.

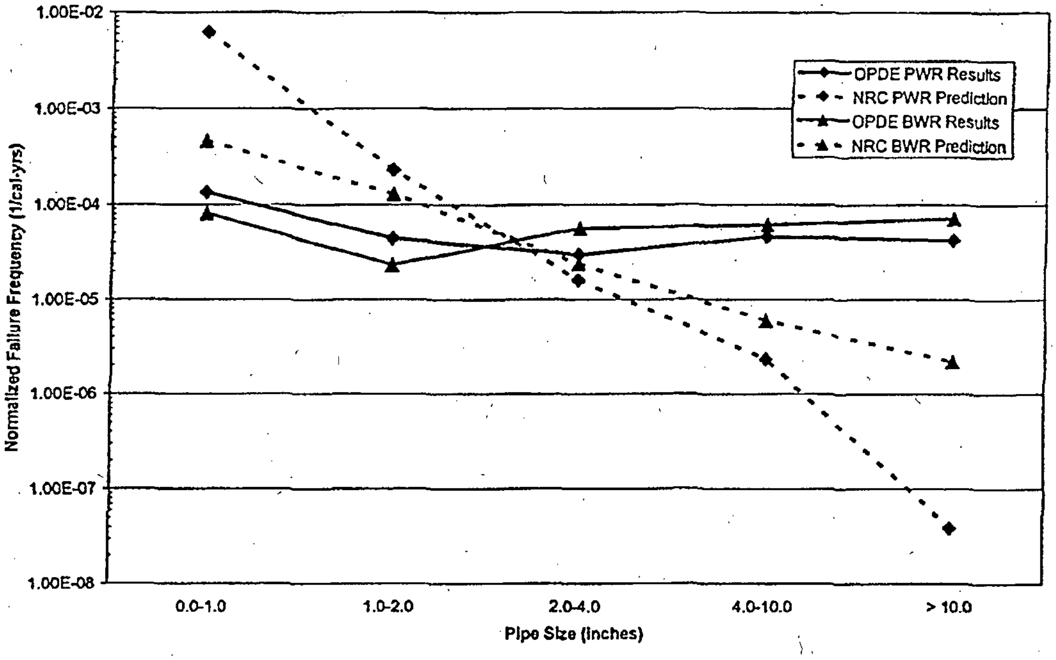

Figure 4.1-1. Normalized pipe failure frequencies as a function of pipe group size for both carbon and stainless steel pipe failures in both BWR and PWR plants.

There were three issues in the data analysis that were initially thought to factor into the difference in results between the analyzed OPDE database and the NRC predictions. The first assumption was that all types of cracks, leaks, ruptures, or other issues were considered to be a complete failure in the pipe. In actuality this is not true since inspections or other indicators may catch a crack or leak before a complete failure occurs. As a result, a separate analysis considering only the pipe ruptures listed in the OPDE database was conducted. However, the calculated frequency distribution considering only ruptures did not change significantly, in either trend or magnitude, from the results obtained when considering all issues to be a failure. The results of this rupture only analysis are shown below in Figure 4.1-2.

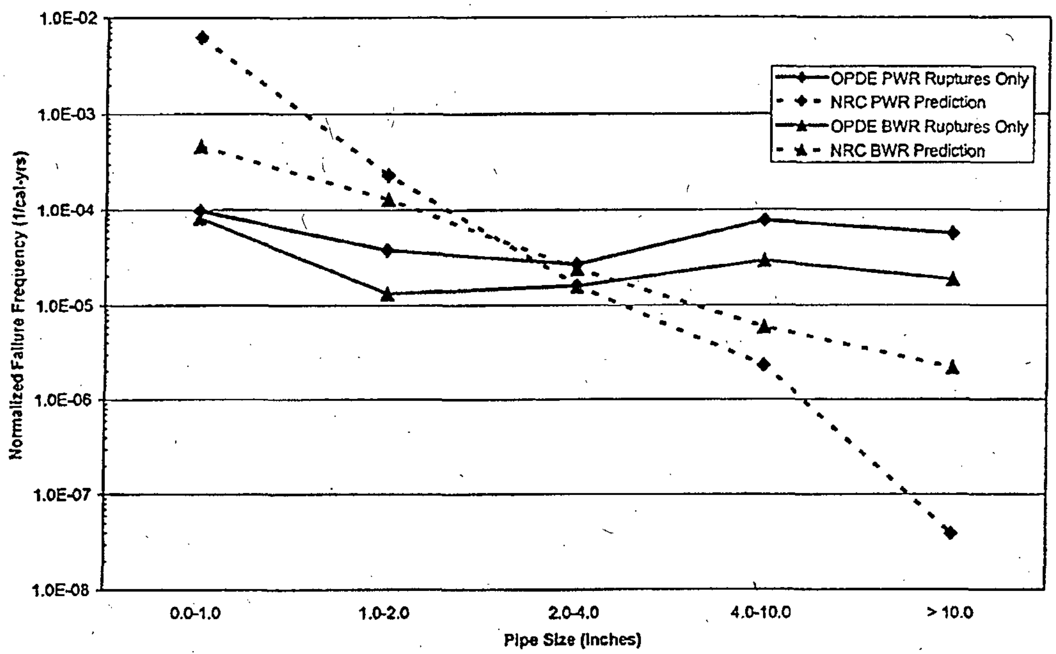

Figure 4.1-2 Normalized rupture frequencies as a function of pipe group size for both carbon and stainless steel pipe failures in both BWR and PWR plants.

The data for this plot is shown in Table 4.1-2.

Table 4.1-2. Normalized Rupture Frequencies.

Plant Type	Pipe Size (inches)	Instances of Rupture	Normalized Failure Frequency (1/cal-yrs)
PWR	0.0-1.0	37	9.8E-05
	1.0-2.0	14	3.7E-05
	2.0-4.0	10	2.7E-05
	4.0-10.0	29	7.7E-05
	> 10.0	21	5.6E-05
	Total	111	---
BWR	0.0-1.0	31	8.2E-05
	1.0-2.0	5	1.3E-05
	2.0-4.0	6	1.6E-05
	4.0-10.0	11	2.9E-05
	> 10.0	7	1.9E-05
	Total	60	---

The second assumption of concern is the nature of the information contained in the OPDE database. Since the "light" version of the database did not specify the exact pipe size due to the proprietary nature of this information, all pipe failures greater than 10 inches were included in one bin for this analysis. However, for the NRC predictions there are two categories for pipes greater than 10 inches, LOCA categories 5 and 6. As a result, the OPDE calculated failure frequencies for the largest pipe group size would be expected to be larger in magnitude than the NRC's predictions since it covers a wider range of pipe sizes, and thereby a greater fraction of the total when normalized.

The final concern is the OPDE database excludes instances of steam generator tube rupture (SGTR) from consideration. By doing this the total number of failures in the smaller pipe size groups is reduced, and the calculated frequencies are lower for the smaller pipe size groups than if SGTR had been considered.

The next two plots, Figure 4.1-3 and Figure 4.1-4, present the same data as is included in Figure 4.1-1, but these figures include the ranges for the NRC prediction. It can be seen that even when the range of validity is taken into consideration, a large portion of the distribution still falls outside the boundaries for both PWRs and BWRs.

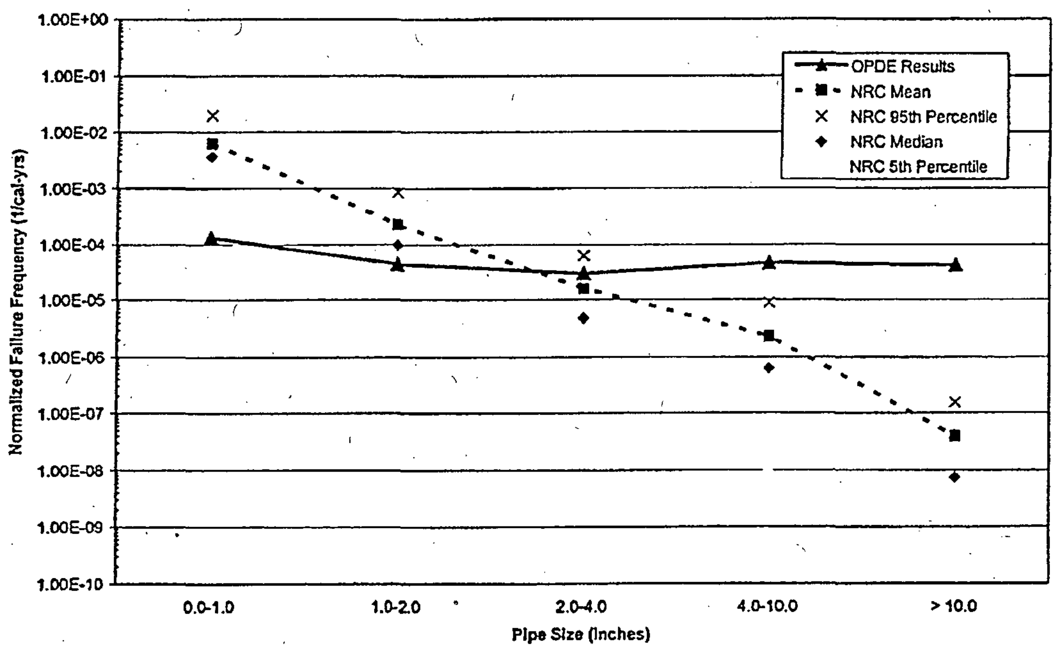

Figure 4.1-3. Normalized Failure Frequency Distribution for PWRs.

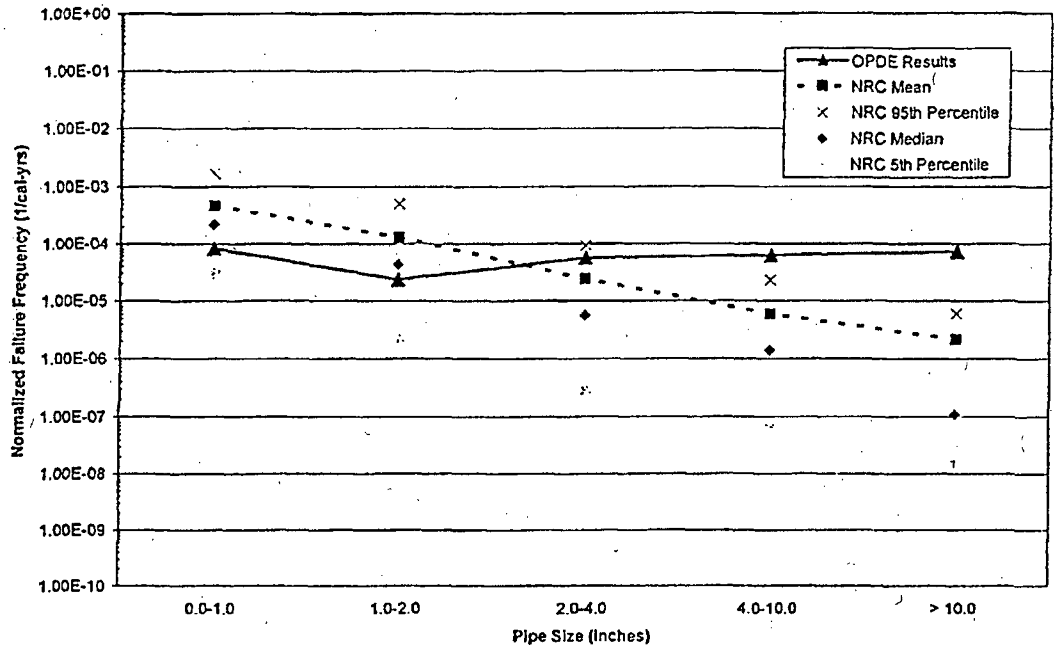

Figure 4.1-4. Normalized Failure Frequency Distribution for BWRs.

Table 4.1-3 and Table 4.1-4 serve as summaries of the information on pipe failure as a function of pipe size and pipe type from the OPDE database for PWRs and BWRs respectively. All the data contained in these tables was normalized based on the total number of failures for the given plant type (1355 for BWR and 1536 for PWR).

Table 4.1-3. Summary of PWR Pipe Failures from OPDE Database as of 2-24-05

Pipe Size (inches)	Both Carbon Steel and Stainless Steel Pipes		Carbon Steel Pipes Only		Stainless Steel Pipes Only	
	Number of Failures	Normalized Failure Frequency (1/cal-yrs)	Number of Failures	Normalized Failure Frequency (1/cal-yrs)	Number of Failures	Normalized Failure Frequency (1/cal-yrs)
0.0-1.0	698	1.3E-04	154	3.0E-05	544	1.0E-04
1.0-2.0	228	4.4E-05	74	1.4E-05	154	3.0E-05
2.0-4.0	153	2.9E-05	78	1.5E-05	75	1.4E-05
4.0-10.0	238	4.6E-05	126	2.4E-05	112	2.2E-05
> 10.0	219	4.2E-05	93	1.8E-05	126	2.4E-05
Total	1536	---	525	---	1011	---

Table 4.1-4. Summary of BWR Pipe Failures from the OPDE Database as of 2-24-05

Pipe Size (inches)	Both Carbon Steel and Stainless Steel Pipes		Carbon Steel Pipes Only		Stainless Steel Pipes Only	
	Number of Failures	Normalized Failure Frequency (1/cal-yrs)	Number of Failures	Normalized Failure Frequency (1/cal-yrs)	Number of Failures	Normalized Failure Frequency (1/cal-yrs)
0.0-1.0	375	8.2E-05	118	2.6E-05	257	5.6E-05
1.0-2.0	107	1.1E-05	32	7.0E-06	75	1.6E-05
2.0-4.0	259	2.6E-05	32	7.0E-06	227	4.9E-05
4.0-10.0	284	2.9E-05	50	1.1E-05	234	5.1E-05
> 10.0	330	3.4E-05	39	8.5E-06	291	6.3E-05
Total	1355	---	271	---	1084	---

There are a few important things to note from these tables. The first is that there have been a similar number of failures reported in BWRs as PWRs (1355 vs. 1536). Second, there were 4 times as many failures of stainless steel pipes as carbon steel pipes in BWRs (1084 vs. 271), and almost two times as many stainless steel failures than carbon steel failures in PWRs (1011 vs. 525). It was not expected to find more stainless steel failures than carbon steel failures. It should also be noted that while the number of stainless steel pipe failures is about the same for both BWRs and PWRs, but nearly twice as many carbon steel failures were observed in PWR plants than BWR plants (525 vs. 271).

Figure 4.1-5 and Figure 4.1-6 shows a more detailed representation of failure frequencies as a function of pipe size for PWR plants only, and BWR plants only, respectively. These figures present the separate failure frequency distributions for carbon steel and stainless steel pipes, where the data is normalized based on the total number of failures for each plant type. Figure 4.1-5 shows that failures of stainless steel pipes are more frequent than carbon steel pipes only for smaller pipe sizes in PWRs. Figure 4.1-6 shows that stainless steel pipe failures are much more frequent than carbon steel pipe failures at all pipe sizes in BWRs.

As previously mentioned, the data for these two figures (4.1-5 and 4.1-6) was normalized using the methodology explained in the Data Analysis Section, using the total number of failures (carbon + stainless) for each plant type. Conducting the analysis in this manner allows for relative comparisons of failure frequencies to be made between the two types of pipes, however, it does not allow for the failure frequencies to be compared to the NRC predictions. As a result, a second analysis was done where the data was normalized based on the number of failures for a given pipe type in each plant type. In other words, the BWR carbon steel failures would be normalized by the total number of carbon failures in BWRs. The results of this modified analysis are given in Figure 4.1-7 and 4.1-8 for PWRs and BWRs, respectively. The summary tables, with the recalculated frequencies, have also been included as Table 4.1-5 and Table 4.1-6.

It can be seen from these two figures that conducting the analysis in this modified manner collapses the data, meaning that the failure frequencies, based strictly on pipe size, are very similar for carbon and stainless steel pipes in both types of plants. However, the fact remains that stainless pipes are still more likely to fail than carbon pipes in both plant types, based in the relative number of failures for each. More importantly, however, conducting this modified analysis did not show any substantial improvement in matching the data to the NRC predictions.

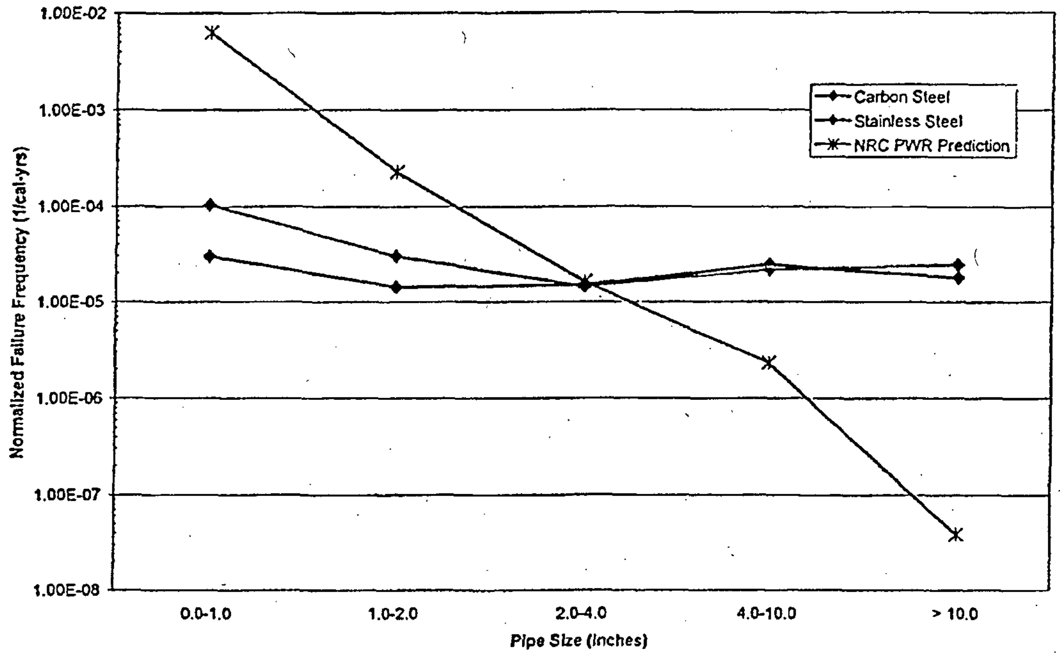

Figure 4.1-5. Normalized pipe failure frequencies as a function of pipe size for PWRs.

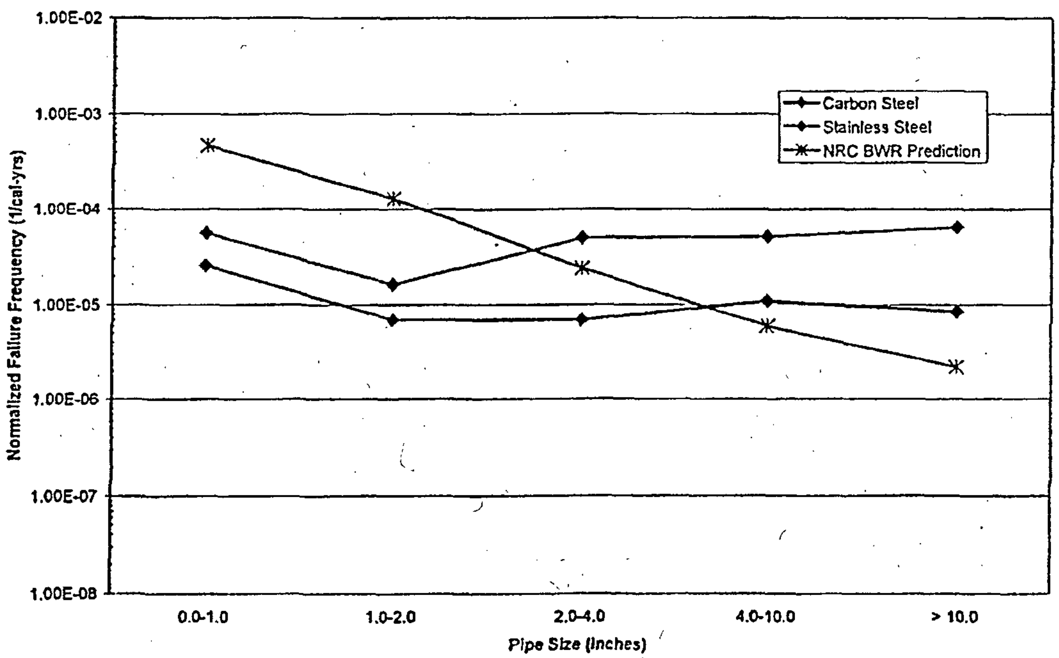

Figure 4.1-6. Normalized pipe failure frequencies as a function of pipe size for BWRs.

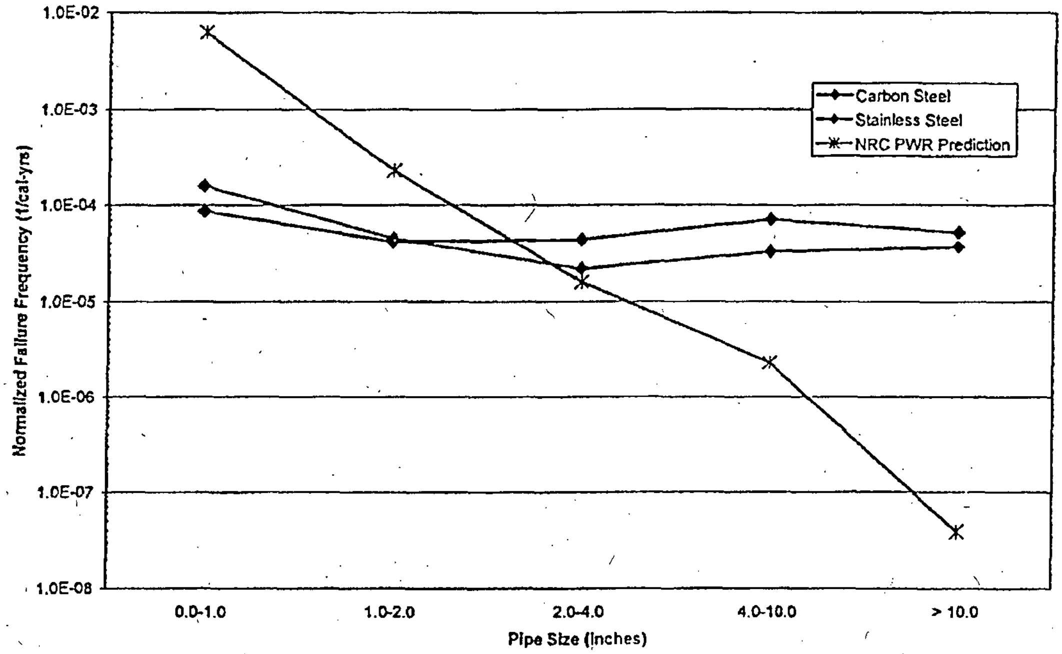

Figure 4.1-7. Normalized pipe failure frequencies as a function of pipe size for PWRs using the Modified Analysis Method.

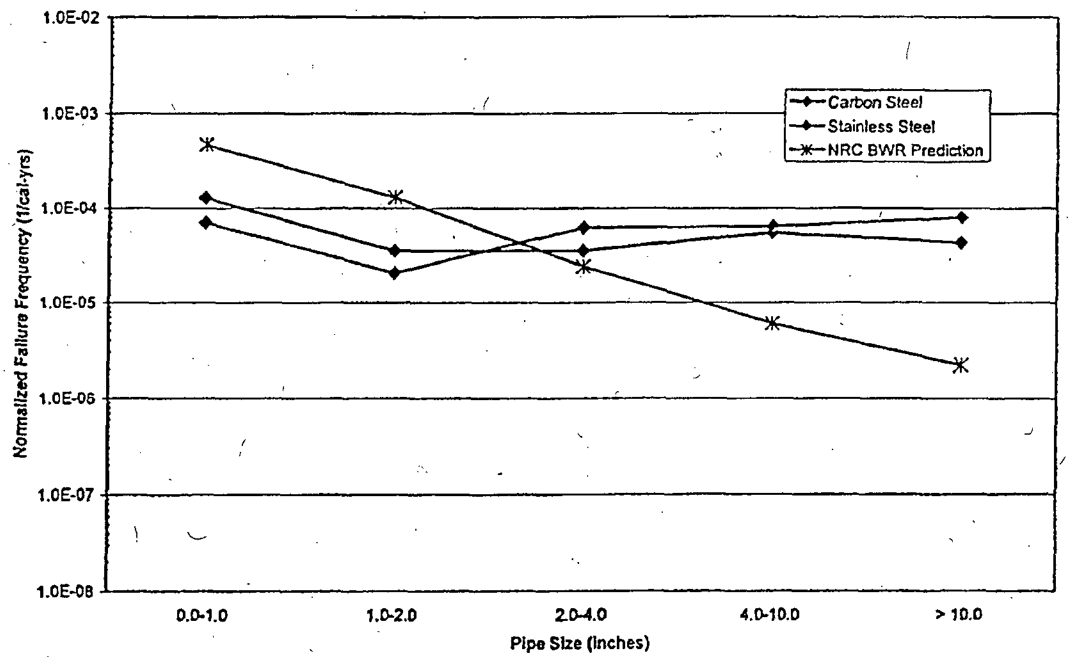

Figure 4.1-8. Normalized pipe failure frequencies as a function of pipe size for BWRs using the Modified Analysis Method.

Table 4.1-5. Summary of PWR Pipe Failures from OPDE Database as of 2-24-05, using the Modified Analysis Method.

Pipe Size (inches)	Both Carbon Steel and Stainless Steel Pipes		Carbon Steel Pipes Only		Stainless Steel Pipes Only	
	Number of Failures	Normalized Failure Frequency (1/cal-yrs)	Number of Failures	Normalized Failure Frequency (1/cal-yrs)	Number of Failures	Normalized Failure Frequency (1/cal-yrs)
0.0-1.0	698	1.3E-04	154	8.7E-05	544	1.6E-04
1.0-2.0	228	4.4E-05	74	4.2E-05	154	4.5E-05
2.0-4.0	153	2.9E-05	78	4.4E-05	75	2.2E-05
4.0-10.0	238	4.6E-05	126	7.1E-05	112	3.3E-05
> 10.0	219	4.2E-05	93	5.2E-05	126	3.7E-05
Total	1536	---	525	---	1011	---

Table 4.1-6. Summary of PWR Pipe Failures from OPDE Database as of 2-24-05, using the Modified Analysis Method.

Pipe Size (inches)	Both Carbon Steel and Stainless Steel Pipes		Carbon Steel Pipes Only		Stainless Steel Pipes Only	
	Number of Failures	Normalized Failure Frequency (1/cal-yrs)	Number of Failures	Normalized Failure Frequency (1/cal-yrs)	Number of Failures	Normalized Failure Frequency (1/cal-yrs)
0.0-1.0	698	1.3E-04	154	3.4E-05	544	7.0E-05
1.0-2.0	228	4.4E-05	74	9.3E-06	154	2.0E-05
2.0-4.0	153	2.9E-05	78	9.3E-06	75	6.2E-05
4.0-10.0	238	4.6E-05	126	1.5E-05	112	6.4E-05
> 10.0	219	4.2E-05	93	1.1E-05	126	7.9E-05
Total	1536	---	525	---	1011	---

4.2 Pipe Failures as a function of Pipe Size from Independent Data

The independent database was used primarily to confirm the OPDE database predictions, along with comparing this set of data to the NRC data. Due to the small number of incidents found in this database, some of the pipe group size data groups had values of zero. When plotted on a semi-log scale, similar to the NRC and the OPDE plots, the points do not appear on the plot for that particular pipe size group. This occurs only once for the total normalized frequency plot for BWR data.

Table 4.2-1 shows the comparison of the OPDE, NRC and the independent database frequencies.

Table 4.2-1. OPDE Calculated, NRC Predicted, and Independent Database Calculated, Normalized Failure Frequencies (1/cal-yrs).

Plant Type	Pipe Size (inches)	OPDE Data	NRC Prediction	Independent Database
PWR	0.0-1.0	1.3E-04	6.3E-03	3.6E-05
	1.0-2.0	4.4E-05	2.3E-04	3.6E-05
	2.0-4.0	2.9E-05	1.6E-05	9.4E-05
	4.0-10.0	4.6E-05	2.3E-06	2.2E-05
	> 10.0	4.2E-05	3.9E-08	1.1E-04
BWR	0.0-1.0	8.2E-05	4.7E-04	2.3E-05
	1.0-2.0	2.3E-05	1.3E-04	0.0E+00
	2.0-4.0	5.6E-05	2.4E-05	3.4E-05
	4.0-10.0	6.2E-05	6.0E-06	2.3E-05
	> 10.0	7.2E-05	2.2E-06	2.2E-04

The Figure 4.2-1 presents the overall normalized frequencies of PWR plants in the United States, and roughly 10 foreign plants for the independent database, the entire OPDE-light, and the NRC mean data given in reports. As seen, the NRC mean values of frequency decrease as the pipe size increases. Although in the two other independent sets of data obtained, the frequencies remain relatively the same throughout the pipe size groups. Pipe sizes which were less than roughly two inches had a lower frequency for the two independent data sets compared to the NRC data, and the pipe sizes above the two to four inches group size show a higher frequency compared to what the NRC's expert elicitation has predicted. This figure shows that the two independent data sources follow similar trends compared to what the NRC's prediction. The PWR frequency shows a vast difference at the higher pipe size groups which in turn contradicts the thinking that larger the pipe size have a smaller break frequency.

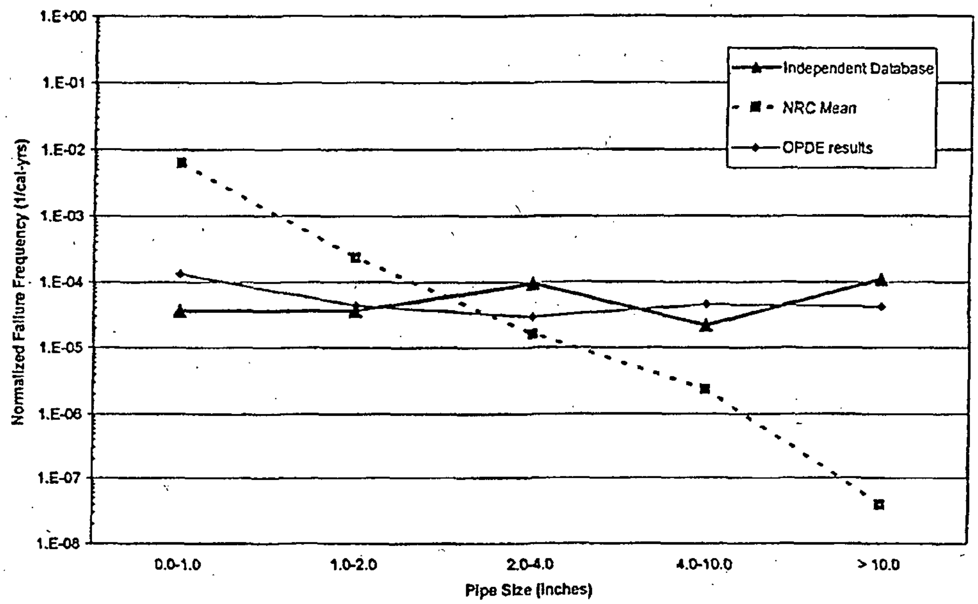

Figure 4.2-1. Normalized pipe failure frequency as a function of Pipe Group Size for PWRs.

Figure 4.2-2 presents the overall BWR data for the independent data, the OPDE-light, and the NRC data. A similar trend for each data set can be seen in BWR's as in PWR's, except that the frequency range is much smaller for BWR's than PWR's. The independent data provided no pipe failures in the pipe size group of one to two inches, and thus on a log-scale, no data point appears on the figure. Once again the independent data and the OPDE-light data coincide throughout the pipe size groups, and contradict the NRC prediction of pipe failure frequencies; except for the range of two to four inches again they are similar. Pipes which are larger than ten inches prove to have a higher frequency in the two independent data sets when compared to that of the NRC data set provided by expert elicitation.

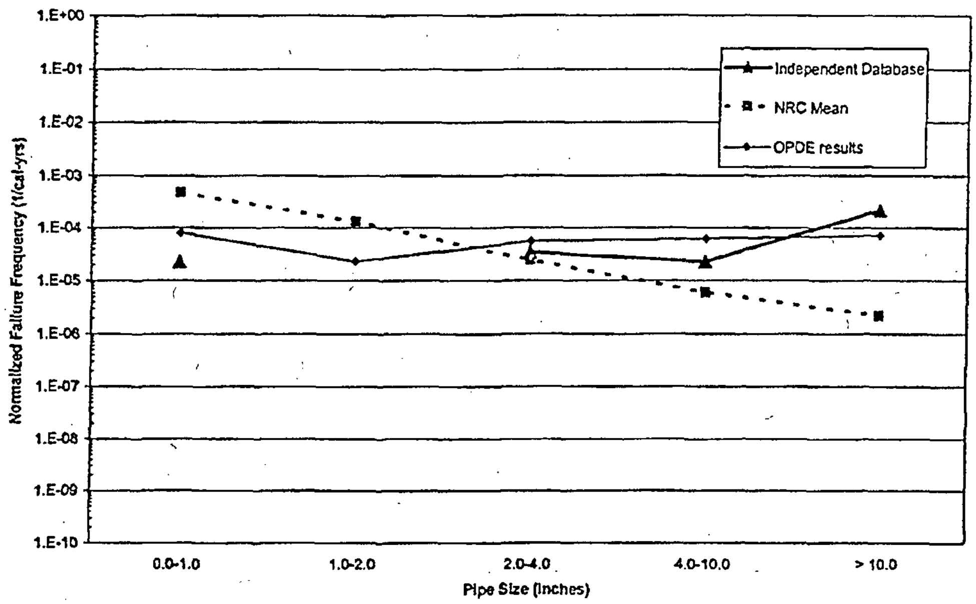

Figure 4.2-2. Normalized pipe failure frequency as a function of Pipe Group Size for BWRs.

Overall, the two independent data sets show contradicting trends when compared to the NRC normalized frequencies. Instead of the double-ended guillotine break being analyzed for every plant for the largest pipe in that plant, the NRC is trying to make the maximum break size which needs to be analyzed ten inches. The reasoning for this is due to low frequency of breaks in pipes of larger diameter than ten inches. This data above shows that the frequency from raw data does not agree with the current NRC predictions by expert elicitation. There is a high frequency of occurrence in pipe sizes greater than ten inches according to the independent data found.

4.3 Pipe Failures as a function of Failure Mechanism

This section of the report summarizes the frequency of failure mechanisms for carbon and stainless steel pipes. The information presented in figures 4.3-1 through 4.3-3 represents the normalized failure frequencies for each failure mechanism. This data is also presented in tabular form in table 4.3-1. The data was collapsed by pipe sizes and broken apart by steel type and plant type. The data was normalized for each type of steel based on the number of reactor years and the total amount of failures (carbon +stainless) for each plant.

Table 4.3-1. Failure Frequencies of Pipes for each Failure Mechanism.

Plant Type	Failure Mechanism	Carbon Steel Failure Frequency	Stainless Steel Failure Frequency	Total Failure Frequency
PWR	Corrosion	2.04E-05	5.38E-06	2.57E-05
PWR	FAC	2.29E-05	2.32E-05	4.61E-05
PWR	MIC	8.26E-06	1.92E-07	8.45E-06
PWR	Erosion	1.84E-05	2.30E-06	2.07E-05
PWR	Fatigue	1.77E-05	9.62E-05	1.14E-04
PWR	Human Factors	6.91E-06	2.42E-05	3.11E-05
PWR	Mechanical Failures	4.23E-06	7.11E-06	1.13E-05
PWR	SCC	9.60E-07	3.25E-05	3.34E-05
PWR	Water Hammer	0.00E+00	3.84E-07	3.84E-07
PWR	Misc	1.15E-06	2.69E-06	3.84E-06
BWR	Corrosion	6.31E-06	6.97E-06	1.33E-05
BWR	FAC	1.26E-05	1.37E-05	2.63E-05
BWR	MIC	1.31E-06	2.18E-07	1.52E-06
BWR	Erosion	8.71E-06	1.96E-06	1.07E-05
BWR	Fatigue	1.55E-05	4.90E-05	6.44E-05
BWR	Human Factors	5.22E-06	1.85E-05	2.37E-05
BWR	Mechanical Failures	3.92E-06	5.44E-06	9.36E-06
BWR	SCC	4.14E-06	1.36E-04	1.40E-04
BWR	Water Hammer	4.35E-07	2.18E-07	6.53E-07
BWR	Misc	8.71E-07	4.14E-06	5.01E-06

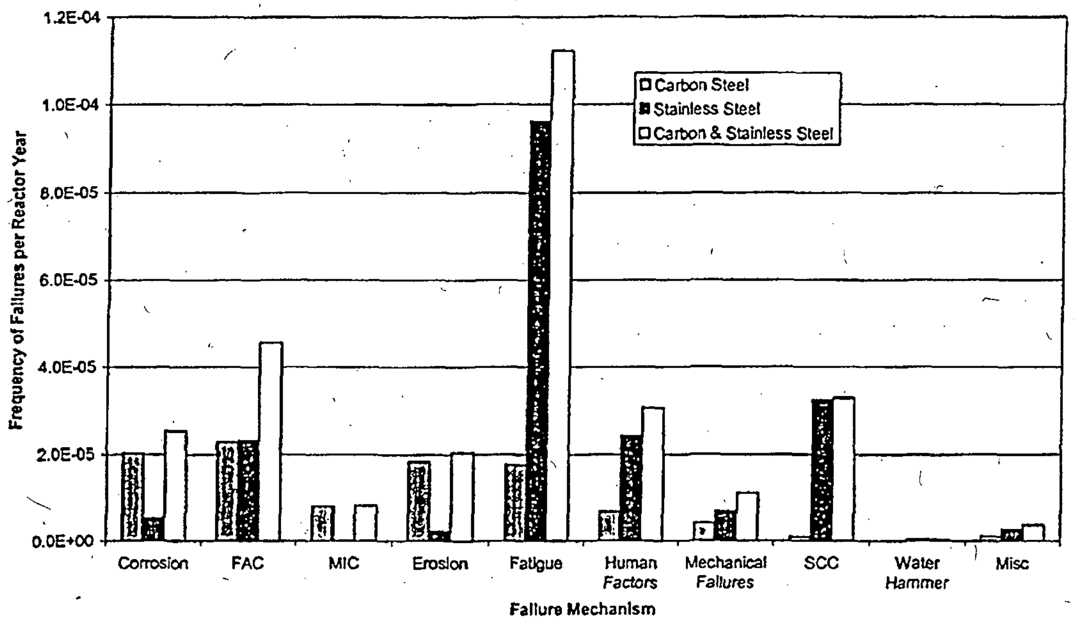

Figure 4.3-1. PWR Failure Frequency for Carbon and Stainless Steel Pipes as a Function of Failure Mechanism

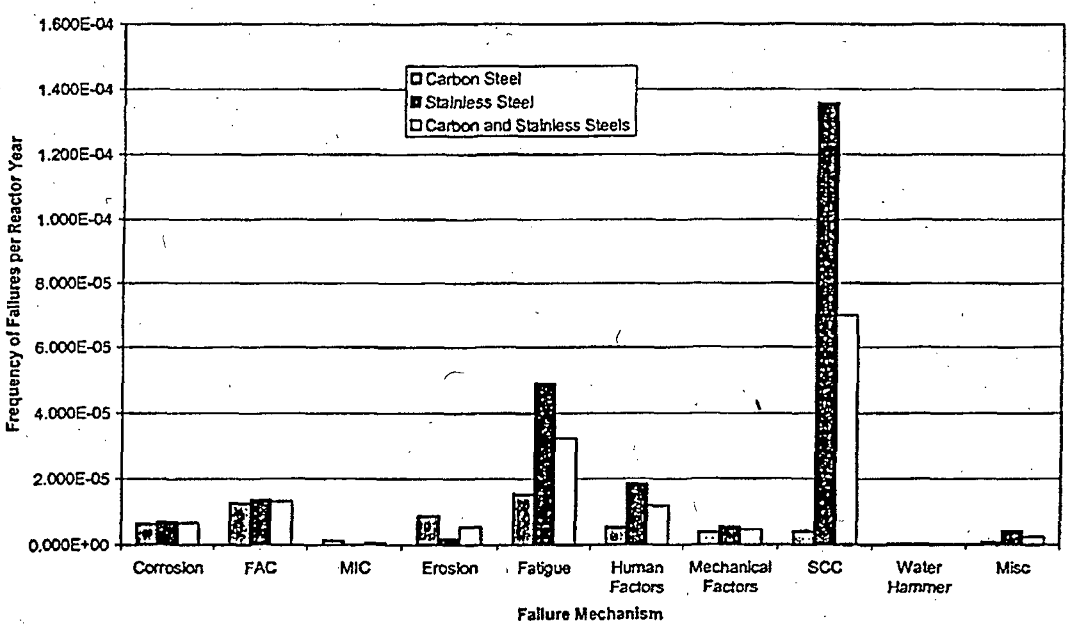

Figure 4.3-2. BWR Failure Frequency for Carbon and Stainless Steel Pipes as a Function of Failure Mechanism

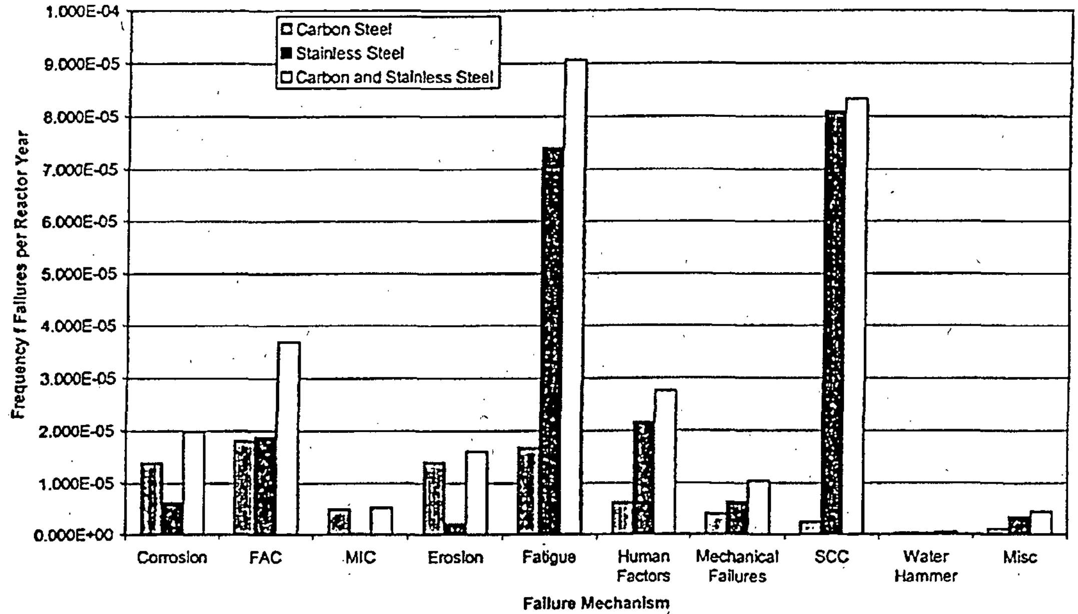

***Figure 4.3-3.* PWR and BWR Failure Frequency for Carbon and Stainless Steel Pipes as a Function of Failure Mechanism**

From these plots it was determined that PWR plants are dominated by fatigue failures and BWR plants are dominated by stress corrosion cracking failures. However, in general the most frequent failure mechanisms for both plants are corrosion, fatigue, mechanical factors, and stress corrosion cracking. These four failure mechanisms were analyzed as a function of pipe size in figures 4.3-4 through 4.4-7.

For these plots corrosion includes general corrosion, flow accelerated corrosion, and microbiological corrosion. Stress corrosion cracking was not included with corrosion because the pipe failure method for stress corrosion cracking is different than the other corrosion types. Though mechanical failure frequency was not the highest, mechanical failures were chosen because they appear to be independent of pipe type and plant type. Human factors were ignored because they are a factor of quality assurance as opposed to the other failure mechanisms which are primarily a factor of operation. In regards to human factors it is not known if they have decreased with reactor operating experience because the dates of failures was not included with the OPDE data.

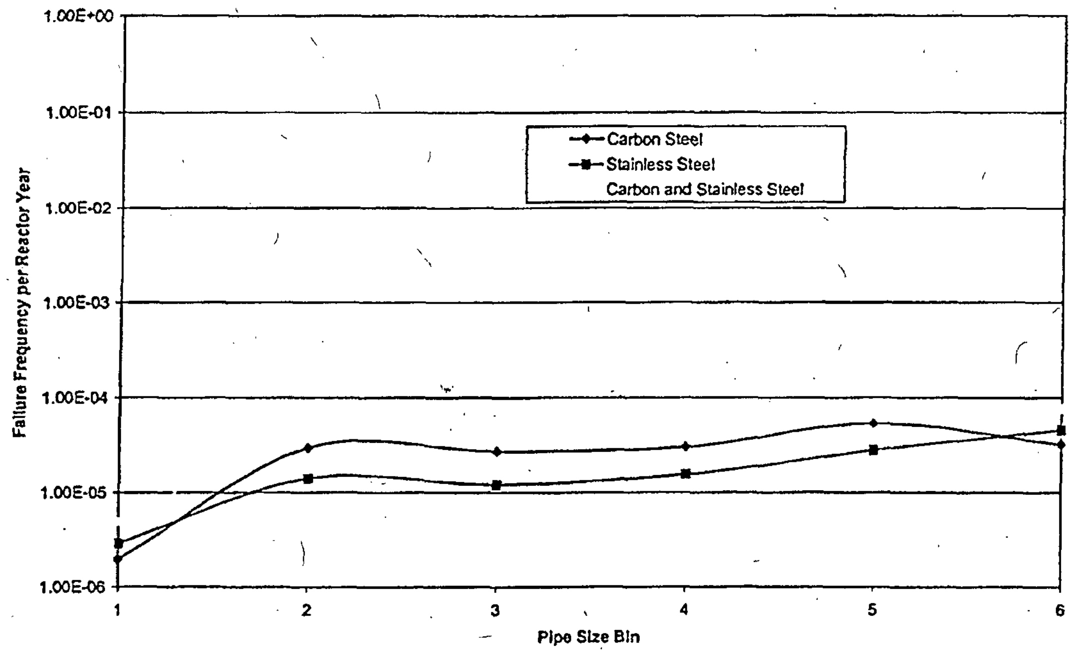

Figure 4.3-4. Pipe Failure by Corrosion as a Function of Pipe Size (PWR & BWR)

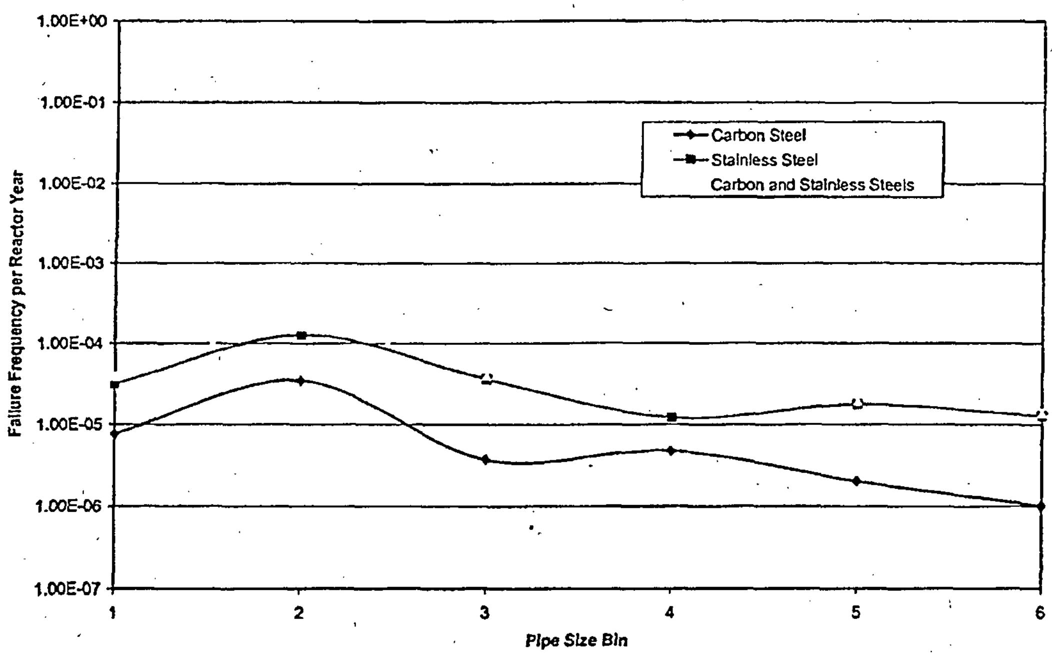

Figure 4.3-5. Pipe Failure by Fatigue as a Function of Pipe Size (PWR & BWR)

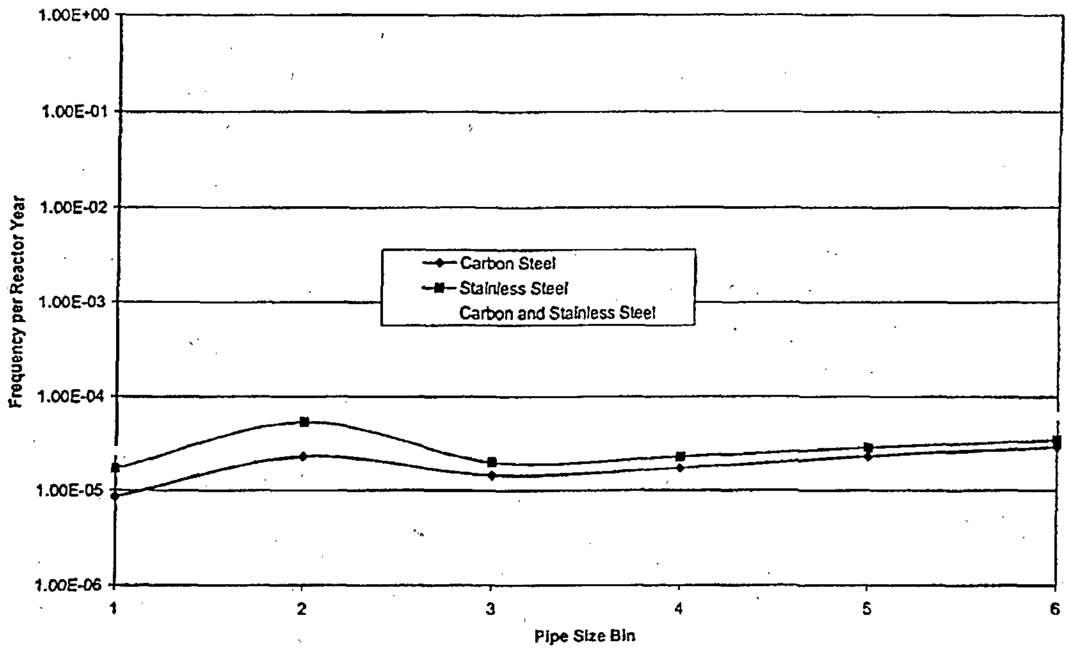

Figure 4.3-6. Pipe Failure by Mechanical Failures as a Function of Pipe Size (PWR & BWR)

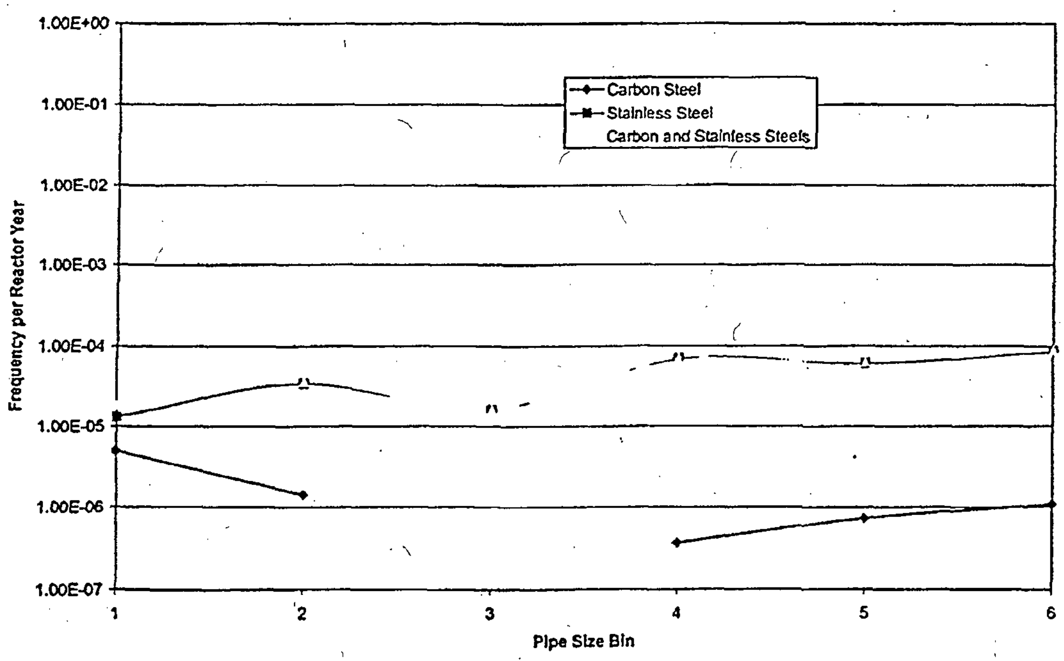

Figure 4.3-7. Pipe Failure by Stress Corrosion Cracking as a Function of Pipe Size (PWR & BWR)

The frequencies of pipe failures by corrosion shown in Figure 4.3-4 are nearly independent of pipe size. With the exception of the smallest of pipe sizes (< 1.0 inches) the frequency of failure for each type of steel is relatively constant. Stainless steel has a lower frequency of failure due to corrosion than carbon steel, which is expected because stainless steel is meant to be corrosion resistant.

Figure 4.3-5 shows that carbon steel is less likely to fail by fatigue than stainless steel for all pipe sizes. The figure also shows that as the pipes increase in size they fail less frequently by fatigue. This is more than likely due to greater movement of the pipes as they decrease in size. The amount of force required to fatigue a larger pipe is greater than that of a smaller pipe.

Figure 4.3-6 supports the information from figure 4.3-3 that shows mechanical failures being relatively equal for all pipe sizes and types. The frequencies of the different pipes in each bin are roughly the same and they stay relatively constant across the spectrum of pipe sizes. The different failures that were grouped into mechanical failures as listed in the section 3.0 are excessive vibration, overpressurization, overstressed, and severe overloading. Though the instances of these failures are low they seem to affect all pipes relatively equally.

Stress corrosion cracking appears to be much more prevalent in stainless steel pipes as opposed to carbon steel pipes as shown in Figure 4.3-7. The discontinuity in the carbon steel data is due to plotting a frequency of zero on a log scale. For both stainless and carbon pipes the frequency of failure increases for the largest pipe size (> 10 inches).

5.0 Conclusions from Data

5.1 Pipe Failures as a function of Pipe Size from OPDE Data

1. The main problem with the OPDE database is it does not have any resolution beyond pipe sizes greater than 10 inches.

2. For both PWRs and BWRs the results of the OPDE database underestimate the failure frequency for the smaller pipe size groups, and overestimate the failure frequency for the larger pipe size groups, compared to the NRC predictions. In both cases the OPDE data does not predict as drastic of a difference in the frequencies for small pipes and large pipes as the NRC does.

3. The OPDE database excludes instances of steam generator tube rupture (SGTR) from consideration. By doing this the total number of failures in the smaller pipe size groups are reduced, and the calculated frequencies are lower at smaller pipe sizes than if SGTR had been considered. This may be one source of difference in the OPDE results and NRC prediction.

4. The OPDE database reports failures of stainless steel pipes are more frequent than carbon steel pipes for smaller pipe sizes in PWRs and stainless steel pipe failures are much more frequent than carbon steel pipe failures at all pipe sizes in BWRs.

5.2 Pipe Failures as a function of Pipe Size from Independent Data

1. The data set collected independently by our group compares very well with the trends observed in the OPDE data, but does not match the results predicted by the NRC.

2. The main problem with this data set is the limited amount of data points.

3. Failure mechanism plots were not made due to the lack of variety in failure mechanisms. The majority of the failure mechanisms were erosion/corrosion and stress corrosion cracking.

5.3 Pipe Failures as a function of Failure Mechanism

1. The failure mechanism that appears to dominate PWR plants is fatigue failure, and BWR plants are dominated by stress corrosion cracking failures. In general both plants are limited by corrosion, fatigue, and stress corrosion cracking.

2. For some failure mechanisms the frequency of failure increases as pipe size increases. Stress corrosion cracking is one failure mechanism where this trend is seen. It should be noted that this does not necessarily contradict the NRC's assertion that larger pipes break less frequently. This conclusion only states that for some failure mechanisms large pipes fail more frequently.

3. Although the OPDE data does not show water hammer to be a significant failure mechanism, it should be noted that the OPDE database listed 450 separate water hammer events where structural pipe integrity was challenged but not failed. Had this data points been included as probable failures, water hammer would have become one of the leading failure mechanisms.

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PLANT TYPE	PIPE TYPE	SYSTEM GROUP	APPARENT CAUSE	PIPE SIZE GROUP	TOTAL NO. OF RECORDS	Crack-Full	Crack-Part	Deformation	Large Leak	Leak	P/H-Leak	Rupture	Severance	Small Leak	Wall thinning
PWR	CS	AUXC	Cavitation	5	1						1				
PWR	CS	AUXC	Cavitation-erosion	5	1									1	
PWR	CS	AUXC	Cavitation-erosion	6	1						1				
PWR	CS	AUXC	Corrosion	2	15				1		2		1	10	1
PWR	CS	AUXC	Corrosion	3	17		1				3			10	3
PWR	CS	AUXC	Corrosion	4	15	1					3			11	
PWR	CS	AUXC	Corrosion	5	20	1				1	9			8	1
PWR	CS	AUXC	Corrosion	6	18	1				1	5			10	1
PWR	CS	AUXC	Erosion-cavitation	6	2									1	1
PWR	CS	AUXC	Erosion-corrosion	1	4						1			3	
PWR	CS	AUXC	Erosion-corrosion	2	17					1	2			14	
PWR	CS	AUXC	Erosion-corrosion	3	15						5			10	
PWR	CS	AUXC	Erosion-corrosion	4	13	1	1			1	4			5	1
PWR	CS	AUXC	Erosion-corrosion	5	20	1				3	5	1		10	
PWR	CS	AUXC	Erosion-corrosion	6	20				3	1	9			7	
PWR	CS	AUXC	External Impact	6	1									1	
PWR	CS	AUXC	FAC - Flow Accelerated Corrosion	6	1									1	
PWR	CS	AUXC	Galvanic Corrosion	2	1									1	
PWR	CS	AUXC	HF CONSTANST	1	1									1	
PWR	CS	AUXC	HF.CONSTANST	2	4									4	
PWR	CS	AUXC	HF.CONSTANST	4	2						1			1	
PWR	CS	AUXC	HF:CONSTANST	5	2		1		1						
PWR	CS	AUXC	HF.Human Error	2	1									1	
PWR	CS	AUXC	HF Human Error	5	1						1				
PWR	CS	AUXC	HF.Welding Error	3	5									5	
PWR	CS	AUXC	HF.Welding Error	6	1						1				
PWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	2	2						1			1	
PWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	3	4						3				1
PWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	4	11						7			1	3
PWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	5	12	1	1			1	3			5	1
PWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	6	3					1	1			1	
PWR	CS	AUXC	Severe overloading	1	1									1	
PWR	CS	AUXC	Severe overloading	4	2								2		
PWR	CS	AUXC	Thermal fatigue	4	1									1	
PWR	CS	AUXC	Unreported	3	1									1	
PWR	CS	AUXC	Vibration-Fatigue	2	17									17	
PWR	CS	AUXC	Vibration-fatigue	4	7	5								2	
PWR	SS	CS	HF.CONSTANST	2	1									1	
PWR	SS	CS	HF.Welding Error	3	1						1				
PWR	SS	CS	IGSCC - Intergranular SCC	5	3						3				
PWR	SS	CS	TGSCC - Transgranular SCC	5	3									3	
PWR	SS	CS	Unreported	5	1									1	
PWR	SS	CS	Vibration-fatigue	2	6		1							5	
PWR	SS	CS	Vibration-fatigue	6	1		1								
PWR	CS	EHC	Severe Overloading	2	2								2		
PWR	CS	EHC	Vibration-Fatigue	1	3					1			1	1	
PWR	CS	EHC	Vibration-Fatigue	2	9							1	1	7	
PWR	CS	EHC	Vibration-fatigue	4	1									1	
PWR	SS	EPS	Vibration-fatigue	1	11		2					2		7	
PWR	SS	EPS	Vibration-fatigue	2	3							1		2	
PWR	CS	FPS	Corrosion	2	4						1			3	
PWR	CS	FPS	Corrosion	3	3						1			2	
PWR	CS	FPS	Corrosion	4	3									3	
PWR	CS	FPS	Corrosion	5	4				1		1	1		1	
PWR	CS	FPS	Corrosion	6	2						1	1			
PWR	CS	FPS	HF.CONSTANST	5	2								1	1	
PWR	CS	FPS	HF.Human error	3	1								1		
PWR	CS	FPS	HF:REPAIR/MAINT	6	1							1			
PWR	CS	FPS	HF:Welding Error	6	1						1				
PWR	CS	FPS	MIC - Microbiologically Induced Corrosion	5	7				1	1	2			1	2
PWR	CS	FPS	MIC - Microbiologically Induced Corrosion	6	4										4
PWR	CS	FPS	Severe overloading	3	1							1			
PWR	CS	FPS	Severe overloading	4	1							1			
PWR	CS	FPS	Severe overloading	5	2							2			
PWR	CS	FPS	Severe overloading	6	1							1			

PWR	SS	FWC	Corrosion	3	3							1		2	
PWR	SS	FWC	Corrosion	4	1					1					
PWR	SS	FWC	Corrosion	5	3		1				1			1	
PWR	SS	FWC	Corrosion-fatigue	4	1		1								
PWR	SS	FWC	Corrosion-fatigue	6	3		2							1	
PWR	SS	FWC	Erosion	2	2									2	
PWR	SS	FWC	Erosion	5	1									1	
PWR	SS	FWC	FAC - Flow Accelerated Corrosion	1	2						1			1	
PWR	SS	FWC	FAC - Flow Accelerated Corrosion	2	4					1	1	1		1	
PWR	SS	FWC	FAC - Flow Accelerated Corrosion	3	7				1		3	1		2	
PWR	SS	FWC	FAC - Flow Accelerated Corrosion	4	11		1			1	2	3		2	2
PWR	SS	FWC	FAC - Flow Accelerated Corrosion	5	27				1	2	1	11		4	8
PWR	SS	FWC	FAC - Flow Accelerated Corrosion	6	67				1	1		7		8	50
PWR	SS	FWC	Fatigue	2	3								1	2	
PWR	SS	FWC	Fatigue	3	1									1	
PWR	SS	FWC	Fatigue	4	1									1	
PWR	SS	FWC	Galvanic Corrosion	3	2					2					
PWR	SS	FWC	HF.CONST/INST	2	2					1				1	
PWR	SS	FWC	HF.CONST/INST	4	2									2	
PWR	SS	FWC	HF CONST/INST	6	1										1
PWR	SS	FWC	HF.Design error	1	1									1	
PWR	SS	FWC	HF.Fabrication Error	4	1										1
PWR	SS	FWC	HF:REPAIR/MAINT	4	1						1				
PWR	SS	FWC	HF:REPAIR/MAINT	6	1									1	
PWR	SS	FWC	HF.Welding Error	1	1									1	
PWR	SS	FWC	HF.Welding Error	2	2						2				
PWR	SS	FWC	HF.Welding error	3	2						1			1	
PWR	SS	FWC	HF.Welding error	5	1									1	
PWR	SS	FWC	HF.Welding Error	6	3		1				1			1	
PWR	SS	FWC	Severe overloading	2	5		1							4	
PWR	SS	FWC	Severe overloading	3	1							1			
PWR	SS	FWC	Severe overloading	4	2			1						1	
PWR	SS	FWC	Severe overloading	5	2		1					1			
PWR	SS	FWC	Severe overloading	6	6		1					4		1	
PWR	SS	FWC	Thermal Fatigue	2	2							1		1	
PWR	SS	FWC	Thermal Fatigue	3	2							1		1	
PWR	SS	FWC	Thermal Fatigue	6	13		9			1				3	
PWR	SS	FWC	Thermal Fatigue - Cycling	6	1									1	
PWR	SS	FWC	Thermal Fatigue - Stratification	6	5		5								
PWR	SS	FWC	Vibration-fatigue	1	5							3		2	
PWR	SS	FWC	Vibration-Fatigue	2	23					1		2	2	18	
PWR	SS	FWC	Vibration-fatigue	3	5	1						3		1	
PWR	SS	FWC	Vibration-Fatigue	4	2					1				1	
PWR	SS	FWC	Vibration-Fatigue	5	4	1	1							2	
PWR	SS	FWC	Vibration-fatigue	6	5		4							1	
PWR	SS	FWC	Water Hammer	6	1							1			
PWR	SS	FWC	Water Hammer	6	1					1					
PWR	CS	IA-SA	Fatigue	2	1								1		
PWR	CS	IA-SA	HF.Human error	1	2							1	1		
PWR	CS	IA-SA	HF Human error	2	2								2		
PWR	CS	IA-SA	Severe overloading	2	1									1	
PWR	CS	IA-SA	Severe overloading	3	1								1		
PWR	CS	IA-SA	Vibration-fatigue	1	4							1	2	1	
PWR	CS	IA-SA	Vibration-fatigue	2	11							5	4	2	
PWR	CS	PCS	Corrosion	2	1									1	
PWR	CS	PCS	Erosion	5	2									2	
PWR	CS	PCS	Erosion	6	1		1								
PWR	CS	PCS	FAC - Flow Accelerated Corrosion	2	4							1		3	
PWR	CS	PCS	FAC - Flow Accelerated Corrosion	3	7							2		5	
PWR	CS	PCS	FAC - Flow Accelerated Corrosion	4	9					1		4		3	1
PWR	CS	PCS	FAC - Flow Accelerated Corrosion	5	28					3		5		20	
PWR	CS	PCS	FAC - Flow Accelerated Corrosion	6	12					2		3		7	
PWR	CS	PCS	Fatigue	5	1									1	
PWR	CS	PCS	Fretting	3	1									1	
PWR	CS	PCS	HF:Welding error	5	1					1					
PWR	CS	PCS	PWSCC	4	1									1	
PWR	CS	PCS	Severe overloading	2	1							1			

PWR	CS	PCS	Severe overloading	6	2							2			
PWR	CS	PCS	Thermal fatigue	3	1									1	
PWR	CS	PCS	Vibration-Fatigue	1	2								1	1	
PWR	CS	PCS	Vibration-fatigue	2	10								1	9	
PWR	CS	PCS	Vibration-fatigue	3	1									1	
PWR	CS	PCS	Vibration-fatigue	5	4									4	
PWR	SS	RAS	B/A-SCC	2	2						1			1	
PWR	SS	RAS	B/A-SCC	3	6		1							4	
PWR	SS	RAS	Brittle-Fracture	1	1				1						
PWR	SS	RAS	Cavitation-erosion	6	1									1	
PWR	SS	RAS	Corrosion	1	1									1	
PWR	SS	RAS	Corrosion	2	2						1			1	
PWR	SS	RAS	Corrosion	4	5					1	3			1	
PWR	SS	RAS	Corrosion	5	2						1			1	
PWR	SS	RAS	ECSCC - External Chloride Induced SCC	1	6						4			2	
PWR	SS	RAS	ECSCC - External Chloride Induced SCC	2	1									1	
PWR	SS	RAS	ECSCC - External Chloride Induced SCC	3	1									1	
PWR	SS	RAS	ECSCC - External Chloride Induced SCC	4	2									2	
PWR	SS	RAS	Erosion-cavitation	4	2									2	
PWR	SS	RAS	Excessive Vibration	3	1									1	
PWR	SS	RAS	FAC - Flow Accelerated Corrosion	2	1									1	
PWR	SS	RAS	FAC - Flow Accelerated Corrosion	3	1									1	
PWR	SS	RAS	Fretting	1	1									1	
PWR	SS	RAS	Fretting	3	1									1	
PWR	SS	RAS	HF.CONST/INST	1	3				1		1			1	
PWR	SS	RAS	HF CONST/INST	2	6				1					5	
PWR	SS	RAS	HF.CONST/INST	3	5						1			4	
PWR	SS	RAS	HF:CONST/INST	4	3									3	
PWR	SS	RAS	HF.Fabrication Error	2	1									1	
PWR	SS	RAS	HF.Human error	2	1									1	
PWR	SS	RAS	HF:Human error	3	1						1				
PWR	SS	RAS	HF.REPAIR/MAINT	1	1									1	
PWR	SS	RAS	HF.Welding Error	1	4						1			3	
PWR	SS	RAS	HF:Welding Error	2	7					1	2			4	
PWR	SS	RAS	HF.Welding Error	3	4	2					1			1	
PWR	SS	RAS	HF:Welding error	4	2						1			1	
PWR	SS	RAS	IGSCC - Intergranular SCC	4	1					1					
PWR	SS	RAS	MIC - Microbiologically Induced Corrosion	2	1									1	
PWR	SS	RAS	Overpressurization	5	1							1			
PWR	SS	RAS	PWSCC	2	2					1				1	
PWR	SS	RAS	PWSCC	3	7						1			6	
PWR	SS	RAS	PWSCC	4	5					1				4	
PWR	SS	RAS	PWSCC	5	3						1			2	
PWR	SS	RAS	Severe overloading	2	1									1	
PWR	SS	RAS	Severe overloading	3	3		3								
PWR	SS	RAS	TGSCC - Transgranular SCC	1	5									5	
PWR	SS	RAS	TGSCC - Transgranular SCC	2	1	1									
PWR	SS	RAS	TGSCC - Transgranular SCC	3	3						1			2	
PWR	SS	RAS	TGSCC - Transgranular SCC	4	1									1	
PWR	SS	RAS	Thermal Fatigue	3	6				1	1				3	
PWR	SS	RAS	Thermal Fatigue	4	2				1					1	
PWR	SS	RAS	Thermal Fatigue - Cycling	3	1		1								
PWR	SS	RAS	Unreported	4	1									1	
PWR	SS	RAS	Unreported	5	1						1				
PWR	SS	RAS	Vibration-fatigue	1	10		1					1		8	
PWR	SS	RAS	Vibration-fatigue	2	105		2		7	3	12	2	3	76	
PWR	SS	RAS	Vibration-fatigue	3	44	1	2		2	7	7			25	
PWR	SS	RAS	Vibration-fatigue	4	10				1		2			7	
PWR	SS	RAS	Vibration-fatigue	5	4		1							3	
PWR	SS	RAS	Vibration-fatigue	6	1									1	
PWR	SS	RCPB	B/A-SCC	1	1									1	
PWR	SS	RCPB	B/A-SCC	2	1									1	
PWR	SS	RCPB	Corrosion	2	2		1			1					
PWR	SS	RCPB	Corrosion-fatigue	2	1				1						
PWR	SS	RCPB	Corrosion-fatigue	4	1							1			
PWR	SS	RCPB	ECSCC - External Chloride Induced SCC	1	1	1									
PWR	SS	RCPB	Fretting	1	1		1								

PWR	SS	RCPB	HF.CONSTANST	1	6				2					3	
PWR	SS	RCPB	HF:CONSTANST	2	12	4			1					7	
PWR	SS	RCPB	HF.CONSTANST	3	2									2	
PWR	SS	RCPB	HF CONSTANST	4	1									1	
PWR	SS	RCPB	HF:CONSTANST	5	1									1	
PWR	SS	RCPB	HF.Design Error	1	1									1	
PWR	SS	RCPB	HF:Design error	2	1							1			
PWR	SS	RCPB	HF:REPAIR/MAINT	1	1							1			
PWR	SS	RCPB	HF Welding Error	1	3						2			1	
PWR	SS	RCPB	HF:Welding Error	2	11					1			1	9	
PWR	SS	RCPB	HF.Welding Error	3	2									2	
PWR	SS	RCPB	HF.Welding error	6	1		1								
PWR	SS	RCPB	Hydrogen embrittlement	1	1				1						
PWR	SS	RCPB	IGSCC - Intergranular SCC	5	1		1								
PWR	SS	RCPB	PWSCC	1	2						1			1	
PWR	SS	RCPB	PWSCC	2	44	26	2			1	4		1	10	
PWR	SS	RCPB	PWSCC	3	6		1							5	
PWR	SS	RCPB	PWSCC	4	3		1							2	
PWR	SS	RCPB	PWSCC	5	2		1							1	
PWR	SS	RCPB	PWSCC	6	7		2				2			3	
PWR	SS	RCPB	Severe overloading	2	3									3	
PWR	SS	RCPB	Severe overloading	3	1							1			
PWR	SS	RCPB	TGSCC - Transgranular SCC	1	7	1	1				1			4	
PWR	SS	RCPB	TGSCC - Transgranular SCC	2	5						1			4	
PWR	SS	RCPB	TGSCC - Transgranular SCC	5	1					1					
PWR	SS	RCPB	Thermal fatigue	1	4									4	
PWR	SS	RCPB	Thermal fatigue	2	1									1	
PWR	SS	RCPB	Thermal fatigue	3	4		1			1	1			1	
PWR	SS	RCPB	Thermal fatigue	6	1		1								
PWR	SS	RCPB	Thermal Fatigue - Cycling	3	1									1	
PWR	SS	RCPB	Thermal Fatigue - Cycling	6	1		1								
PWR	SS	RCPB	Vibration-Fatigue	1	31				1	5			1	24	
PWR	SS	RCPB	Vibration-Fatigue	2	82	2			3	10	1			66	
PWR	SS	RCPB	Vibration-fatigue	3	11					4				7	
PWR	SS	RCPB	Vibration-fatigue	4	2					1				1	
PWR	SS	RCPB	Vibration-Fatigue	6	2									2	
PWR	SS	RCS-INSTR	Fatigue	1	1									1	
PWR	SS	RCS-INSTR	HF.CONST/INST	1	1					1					
PWR	SS	RCS-INSTR	HF:CONST/INST	2	1				1						
PWR	SS	RCS-INSTR	Vibration-Fatigue	1	1									1	
PWR	SS	RCS-INSTR	Vibration-fatigue	2	1									1	
PWR	CS	SG	Corrosion	1	1									1	
PWR	CS	SG	Deformation/Thermal Fatigue	2	1									1	
PWR	CS	SG	FAC - Flow Accelerated Corrosion	3	3							1		2	
PWR	CS	SG	HF.Welding Error	6	1						1				
PWR	CS	SG	PWSCC	1	3	3									
PWR	CS	SG	TGSCC - Transgranular SCC	2	1									1	
PWR	CS	SG	Vibration-Fatigue	2	2									2	
PWR	CS	SG	Vibration-fatigue	4	1									1	
PWR	SS	SIR	B/A-SCC	3	1									1	
PWR	SS	SIR	B/A-SCC	5	3		1							2	
PWR	SS	SIR	Cavitation-erosion	3	1							1			
PWR	SS	SIR	Cavitation-erosion	6	2									2	
PWR	SS	SIR	Corrosion	2	1									1	
PWR	SS	SIR	ECSCC - External Chloride Induced SCC	5	3		2				1				
PWR	SS	SIR	ECSCC - External Chloride Induced SCC	6	1						1				
PWR	SS	SIR	Erosion-cavitation	2	3						1			2	
PWR	SS	SIR	FAC - Flow Accelerated Corrosion	2	1						1				
PWR	SS	SIR	Freezing	1	1	1									
PWR	SS	SIR	Fretting	6	1										1
PWR	SS	SIR	HF.CONSTANST	1	1									1	
PWR	SS	SIR	HF:CONSTANST	2	4						1			3	
PWR	SS	SIR	HF.CONSTANST	5	2					1				1	
PWR	SS	SIR	HF Human error	2	1									1	
PWR	SS	SIR	HF.REPAIR/MAINT	6	1									1	
PWR	SS	SIR	HF.Welding Error	1	3						2			1	
PWR	SS	SIR	HF:Welding error	2	7					1	1	1		4	

PWR	SS	SIR	HF.Welding Error	3	1									1	
PWR	SS	SIR	HF.Welding Error	4	2						1			1	
PWR	SS	SIR	HF.Welding Error	5	2	1	1								
PWR	SS	SIR	HF.Welding Error	6	1		1								
PWR	SS	SIR	Overstressed	1	3									3	
PWR	SS	SIR	PWSCC	2	1						1				
PWR	SS	SIR	PWSCC	3	5									5	
PWR	SS	SIR	PWSCC	4	2		2								
PWR	SS	SIR	PWSCC	5	17		2			2	3			10	
PWR	SS	SIR	Severe Overloading	1	1									1	
PWR	SS	SIR	Severe overloading	2	3							2		1	
PWR	SS	SIR	Severe overloading	5	2		1							1	
PWR	SS	SIR	Severe overloading	6	2		1	1							
PWR	SS	SIR	TGSCC - Transgranular SCC	1	1	1									
PWR	SS	SIR	TGSCC - Transgranular SCC	2	1									1	
PWR	SS	SIR	TGSCC - Transgranular SCC	4	1						1				
PWR	SS	SIR	TGSCC - Transgranular SCC	6	1		1								
PWR	SS	SIR	Thermal fatigue	3	1		1								
PWR	SS	SIR	Thermal fatigue	4	3		2		1						
PWR	SS	SIR	Thermal fatigue	6	8		2		2	4					
PWR	SS	SIR	Thermal Fatigue - Cycling	3	1		1								
PWR	SS	SIR	Thermal Fatigue - Cycling	4	1									1	
PWR	SS	SIR	Unreported	3	2									2	
PWR	SS	SIR	Unreported	5	1		1								
PWR	SS	SIR	Unreported	6	1						1				
PWR	SS	SIR	Vibration-fatigue	0	3					1		1		1	
PWR	SS	SIR	Vibration-fatigue	1	8							2		6	
PWR	SS	SIR	Vibration-fatigue	2	42		2		1	3	3	2		31	
PWR	SS	SIR	Vibration-fatigue	3	9		1						1	7	
PWR	SS	SIR	Vibration-fatigue	4	3									3	
PWR	SS	SIR	Vibration-fatigue	5	7	1	1			1				4	
PWR	CS	STEAM	Corrosion	3	1					1					
PWR	CS	STEAM	Corrosion-fatigue	6	1									1	
PWR	CS	STEAM	Erosion	4	1									1	
PWR	CS	STEAM	Erosion	5	1						1				
PWR	CS	STEAM	FAC - Flow Accelerated Corrosion	2	10							1		9	
PWR	CS	STEAM	FAC - Flow Accelerated Corrosion	3	9									9	
PWR	CS	STEAM	FAC - Flow Accelerated Corrosion	4	8					1	1	1		5	
PWR	CS	STEAM	FAC - Flow Accelerated Corrosion	5	14					1		3		9	1
PWR	CS	STEAM	FAC - Flow Accelerated Corrosion	6	14					1		1		10	2
PWR	CS	STEAM	Fretting	3	1						1				
PWR	CS	STEAM	HF.CONSTANST	2	3							1		2	
PWR	CS	STEAM	HF.Human Error	2	1							1			
PWR	CS	STEAM	HF Human error	6	1									1	
PWR	CS	STEAM	HF.Welding Error		1						1				
PWR	CS	STEAM	HF.Welding Error	3	1						1				
PWR	CS	STEAM	HF.Welding error	6	2		2								
PWR	CS	STEAM	Overstressed	1	1					1					
PWR	CS	STEAM	Severe overloading	4	1									1	
PWR	CS	STEAM	Severe overloading	5	2							2			
PWR	CS	STEAM	Severe overloading	6	3		2					1			
PWR	CS	STEAM	Vibration-fatigue	1	2							1		1	
PWR	CS	STEAM	Vibration-fatigue	2	9		1					1	1	6	
PWR	CS	STEAM	Vibration-fatigue	3	2							1		1	
PWR	CS	STEAM	Vibration-fatigue	4	1									1	
PWR	CS	STEAM	Vibration-fatigue	6	1									1	

PLANT TYPE	PIPE TYPE	SYSTEM GROUP	APPARENT CAUSE	PIPE SIZE GROUP	TOTAL NO. OF RECORDS	Crack-Full	Crack-Part	Deformation	Large Leak	Leak	P/H-Leak	Rupture	Severance	Small Leak	Wall thinning
BWR	CS	AUXC	Corrosion	1	1				1						
BWR	CS	AUXC	Corrosion	2	4						1			3	
BWR	CS	AUXC	Corrosion	3	2					1				1	
BWR	CS	AUXC	Corrosion	4	3					1	1			1	
BWR	CS	AUXC	Corrosion	5	4					1	1			1	1
BWR	CS	AUXC	Corrosion	6	7				2		2			2	1
BWR	CS	AUXC	Erosion-cavitation	3	1						1				
BWR	CS	AUXC	Erosion-cavitation	6	1						1				
BWR	CS	AUXC	Erosion-corrosion	3	4						2			2	
BWR	CS	AUXC	Erosion-corrosion	4	7				1	2	1			3	
BWR	CS	AUXC	Erosion-corrosion	5	9						3			5	1
BWR	CS	AUXC	Erosion-corrosion	6	15					2	8			2	3
BWR	CS	AUXC	HF.CONST/INST	2	1									1	
BWR	CS	AUXC	HF:CONST/INST	5	1						1				
BWR	CS	AUXC	HF:Fabrication Error	5	1		1								
BWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	2	1					1					
BWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	4	2						2				
BWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	5	1						1				
BWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	6	1									1	
BWR	CS	AUXC	Severe overloading	3	3									3	
BWR	CS	AUXC	Severe overloading	5	2							1		1	
BWR	CS	AUXC	Severe overloading	6	2								2		
BWR	CS	AUXC	Unreported	6	1									1	
BWR	CS	AUXC	Vibration-fatigue	2	11					1			2	8	
BWR	CS	AUXC	Vibration-Fatigue	3	1									1	
BWR	CS	AUXC	Vibration-Fatigue	4	1									1	
BWR	CS	AUXC	Vibration-Fatigue	5	1	1									
BWR	SS	Containment System	Brittle fracture	6	1		1								
BWR	SS	Containment System	Corrosion	2	1									1	
BWR	SS	Containment System	HF.CONST/INST	5	1		1								
BWR	SS	Containment System	IGSCC - Intergranular SCC	6	1		1								
BWR	SS	Containment System	Severe overloading	6	1								1		
BWR	SS	Containment System	Severe overloading	6	2	1								1	
BWR	SS	Containment System	Vibration-Fatigue	1	1								1		
BWR	SS	CS	Fatigue	1	1							1			
BWR	SS	CS	HF.Welding Error	0	1										1
BWR	SS	CS	IGSCC - Intergranular SCC	4	1						1				
BWR	SS	CS	TGSCC - Transgranular SCC	6	1									1	
BWR	CS	EHC		2	1					1					
BWR	CS	EHC	Fretting	1	2					1	1				
BWR	CS	EHC	HF:CONST/INST	1	1									1	
BWR	CS	EHC	HF:Human error	1	1									1	
BWR	CS	EHC	HF.Human error	4	1									1	
BWR	CS	EHC	HF.Welding Error	2	1							1			
BWR	CS	EHC	Vibration-Fatigue	1	3							3			
BWR	CS	EHC	Vibration-fatigue	2	7				1	2		2		2	
BWR	CS	EHC	Vibration-fatigue	3	1									1	
BWR	SS	EPS	Fatigue	1	1								1		
BWR	SS	EPS	Vibration-fatigue	1	7							1	2	4	
BWR	SS	EPS	Vibration-fatigue	2	2									2	
BWR	CS	FPS	Corrosion	1	1						1				
BWR	CS	FPS	Corrosion	4	1						1				
BWR	CS	FPS	Corrosion	5	2					1	1				
BWR	CS	FPS	FAC - Flow Accelerated Corrosion	4	1						1				
BWR	CS	FPS	Fretting	5	1									1	
BWR	CS	FPS	HF.CONST/INST	5	1								1		
BWR	CS	FPS	HF.Human error	3	1							1			
BWR	CS	FPS	HF:Human Error	6	1				1						
BWR	CS	FPS	HF.INST/CONST	5	1									1	
BWR	CS	FPS	HF.Welding Error	4	1						1				
BWR	CS	FPS	MIC - Microbiologically Induced Corrosion	3	1						1				
BWR	CS	FPS	Severe overloading	4	1							1			
BWR	CS	FPS	Severe Overloading	5	2									2	
BWR	CS	FPS	Vibration-fatigue	1	1									1	
BWR	CS	FPS	Vibration-fatigue	3	1								1		

BWR	SS	FWC	Corrosion	2	2									2	
BWR	SS	FWC	Corrosion	3	1				1						
BWR	SS	FWC	Corrosion	4	2									2	
BWR	SS	FWC	Corrosion	5	2									2	
BWR	SS	FWC	Corrosion	6	1									1	
BWR	SS	FWC	Corrosion-fatigue	2	1		1								
BWR	SS	FWC	Corrosion-fatigue	3	1									1	
BWR	SS	FWC	ECSCC - External Chloride Induced SCC	1	1						1				
BWR	SS	FWC	Erosion	2	2									2	
BWR	SS	FWC	Erosion	3	1						1				
BWR	SS	FWC	Erosion	4	1									1	
BWR	SS	FWC	Erosion	5	1									1	
BWR	SS	FWC	Erosion-cavitation	4	2		1				1				
BWR	SS	FWC	Erosion-cavitation	5	2						2				
BWR	SS	FWC	FAC - Flow Accelerated Corrosion	1	1									1	
BWR	SS	FWC	FAC - Flow Accelerated Corrosion	2	4					1				3	
BWR	SS	FWC	FAC - Flow Accelerated Corrosion	3	2				1					1	
BWR	SS	FWC	FAC - Flow Accelerated Corrosion	4	3						1			2	
BWR	SS	FWC	FAC - Flow Accelerated Corrosion	5	22		1			1	1	1		10	8
BWR	SS	FWC	FAC - Flow Accelerated Corrosion	6	20							2		1	17
BWR	SS	FWC	Fatigue	6	1									1	
BWR	SS	FWC	HF.CONST/INST	4	1									1	
BWR	SS	FWC	HF.CONST/INST	5	1									1	
BWR	SS	FWC	HF.CONST/INST	6	1		1								
BWR	SS	FWC	HF:Human error	1	1								1		
BWR	SS	FWC	HF.Welding Error	2	2									2	
BWR	SS	FWC	HF Welding error	5	1									1	
BWR	SS	FWC	IGSCC - Intergranular SCC	4	1						1				
BWR	SS	FWC	Severe overloading	1	1								1		
BWR	SS	FWC	Severe overloading	3	1							1			
BWR	SS	FWC	Severe overloading	4	1							1			
BWR	SS	FWC	Severe overloading	5	3							2		1	
BWR	SS	FWC	Severe overloading	6	1							1			
BWR	SS	FWC	SICC - Strain-rate Induced Corrosion Cracking	2	1									1	
BWR	SS	FWC	SICC - Strain-rate Induced Corrosion Cracking	4	1									1	
BWR	SS	FWC	SICC - Strain-rate Induced Corrosion Cracking	5	3		1							2	
BWR	SS	FWC	SICC - Strain-rate Induced Corrosion Cracking	6	4		3							1	
BWR	SS	FWC	Thermal fatigue	2	3									3	
BWR	SS	FWC	Thermal Fatigue	3	3		1			1		1			
BWR	SS	FWC	Thermal fatigue	5	5		5								
BWR	SS	FWC	Thermal fatigue	6	5		4							1	
BWR	SS	FWC	Unreported	3	1									1	
BWR	SS	FWC	Unreported	4	1									1	
BWR	SS	FWC	Unreported	6	2		1					1			
BWR	SS	FWC	Vibration-fatigue	1	2				1					1	
BWR	SS	FWC	Vibration-fatigue	2	21					1		3	2	15	
BWR	SS	FWC	Vibration-fatigue	3	8		1				1	1		5	
BWR	SS	FWC	Vibration-fatigue	4	3							1		2	
BWR	SS	FWC	Vibration-fatigue	5	5					1		1	1	2	
BWR	SS	FWC	Vibration-fatigue	6	1		1								
BWR	CS	IA-SA		2	1					1					
BWR	CS	IA-SA	Corrosion	2	1							1			
BWR	CS	IA-SA	Fretting	2	1					1					
BWR	CS	IA-SA	HF:Human error	1	1								1		
BWR	CS	IA-SA	IGSCC - Intergranular SCC	2	1									1	
BWR	CS	IA-SA	Severe Overloading	1	1								1		
BWR	CS	IA-SA	Severe Overloading	2	1									1	
BWR	CS	IA-SA	Vibration-fatigue	1	5					1		1	3		
BWR	CS	IA-SA	Vibration-Fatigue	2	4					1		1	1	1	
BWR	CS	PCS			1					1					
BWR	CS	PCS	Corrosion	1	1									1	
BWR	CS	PCS	Corrosion	3	1									1	
BWR	CS	PCS	Erosion	6	1									1	
BWR	CS	PCS	FAC - Flow Accelerated Corrosion	2	2				1					1	
BWR	CS	PCS	FAC - Flow Accelerated Corrosion	3	1									1	
BWR	CS	PCS	FAC - Flow Accelerated Corrosion	4	6									6	
BWR	CS	PCS	FAC - Flow Accelerated Corrosion	5	12							4		8	

BWR	CS	PCS	FAC - Flow Accelerated Corrosion	6	2							1		1	
BWR	CS	PCS	HF.Welding error	2	1									1	
BWR	CS	PCS	Severe overloading	2	2					1				1	
BWR	CS	PCS	Severe overloading	6	2							1		1	
BWR	CS	PCS	Thermal fatigue	2	1							1			
BWR	CS	PCS	Vibration-fatigue	1	1							1			
BWR	CS	PCS	Vibration-fatigue	2	7							4		3	
BWR	CS	PCS	Vibration-fatigue	3	1							1			
BWR	CS	PCS	Vibration-fatigue	4	2									2	
BWR	SS	RAS	Cavitation-erosion	6	1						1				
BWR	SS	RAS	Corrosion	2	3					2			1		
BWR	SS	RAS	Corrosion	3	4									4	
BWR	SS	RAS	Corrosion	4	6									6	
BWR	SS	RAS	Corrosion	6	3									3	
BWR	SS	RAS	Corrosion-fatigue	1	1									1	
BWR	SS	RAS	ECSCC - External Chloride Induced SCC	1	1									1	
BWR	SS	RAS	ECSCC - External Chloride Induced SCC	2	17		8							9	
BWR	SS	RAS	ECSCC - External Chloride Induced SCC	3	2	2									
BWR	SS	RAS	FAC - Flow Accelerated Corrosion	3	1						1				
BWR	SS	RAS	Fatigue	4	1		1								
BWR	SS	RAS	HF.CONST/INST	2	1									1	
BWR	SS	RAS	HF:CONST/INST	3	1						1				
BWR	SS	RAS	HF.CONST/INST	4	1									1	
BWR	SS	RAS	HF.CONST/INST	5	1									1	
BWR	SS	RAS	HF.Human error	1	1								1		
BWR	SS	RAS	HF:Human error	2	2				1				1		
BWR	SS	RAS	HF REPAIR/MAINT	1	1								1		
BWR	SS	RAS	HF REPAIR/MAINT	2	1									1	
BWR	SS	RAS	HF.REPAIR/MAINT	4	1		1								
BWR	SS	RAS	HF.Welding error	2	2						2				
BWR	SS	RAS	HF:Welding error	3	2						1			1	
BWR	SS	RAS	HF.Welding error	4	1									1	
BWR	SS	RAS	HF.Welding Error	6	4		1				1			2	
BWR	SS	RAS	IDSCC - Interdendritic SCC	4	1					1					
BWR	SS	RAS	IGSCC - Intergranular SCC	2	5						1			4	
BWR	SS	RAS	IGSCC - Intergranular SCC	3	4						2			2	
BWR	SS	RAS	IGSCC - Intergranular SCC	4	56	1	32				9		1	13	
BWR	SS	RAS	IGSCC - Intergranular SCC	5	56	2	35			4	8			7	
BWR	SS	RAS	IGSCC - Intergranular SCC	6	2		1				1				
BWR	SS	RAS	Severe overloading	1	1							1			
BWR	SS	RAS	Severe overloading	2	3			1				2			
BWR	SS	RAS	Severe overloading	4	1							1			
BWR	SS	RAS	TGSCC - Transgranular SCC	1	1									1	
BWR	SS	RAS	TGSCC - Transgranular SCC	2	7	1	1				1			4	
BWR	SS	RAS	TGSCC - Transgranular SCC	3	7		6							1	
BWR	SS	RAS	TGSCC - Transgranular SCC	4	96		96								
BWR	SS	RAS	TGSCC - Transgranular SCC	5	1					1					
BWR	SS	RAS	Thermal fatigue	1	1									1	
BWR	SS	RAS	Thermal fatigue	2	2						1			1	
BWR	SS	RAS	Thermal fatigue	3	1		1								
BWR	SS	RAS	Thermal Fatigue	4	1									1	
BWR	SS	RAS	Thermal fatigue	5	10		5							5	
BWR	SS	RAS	Thermal Fatigue - Cycling	4	3									3	
BWR	SS	RAS	Thermal Fatigue - Cycling	5	1		1								
BWR	SS	RAS	Thermal Fatigue - Cycling	6	1		1								
BWR	SS	RAS	Unreported	3	1		1								
BWR	SS	RAS	Unreported	5	1									1	
BWR	SS	RAS	Vibration-fatigue	1	4		1							3	
BWR	SS	RAS	Vibration-fatigue	2	15				1		1	1	1	11	
BWR	SS	RAS	Vibration-fatigue	3	7		1		1	1				4	
BWR	SS	RAS	Vibration-fatigue	4	2		1							1	
BWR	SS	RAS	Vibration-fatigue	5	1									1	
BWR	SS	RAS	Water Hammer	1	1				1						
BWR	SS	RCPB		2	1										1
BWR	SS	RCPB	Corrosion	1	1									1	
BWR	SS	RCPB	Corrosion	2	1						1				
BWR	SS	RCPB	ECSCC - External Chloride Induced SCC	1	3	2								1	

BWR	SS	RCPB	ECSCC - External Chloride induced SCC	4	1		1								
BWR	SS	RCPB	Erosion	2	1					1					
BWR	SS	RCPB	external damage	3	1			1							
BWR	SS	RCPB	HF:CONSTANST	1	1						1				
BWR	SS	RCPB	HF:CONSTANST	6	2		2								
BWR	SS	RCPB	HF:Fabrication Error	2	1						1				
BWR	SS	RCPB	HF:Fabrication Error	3	1									1	
BWR	SS	RCPB	HF:Fabrication Error	6	1		1								
BWR	SS	RCPB	HF:REPAIR/MAINT	2	1									1	
BWR	SS	RCPB	HF.Welding error	1	1						1				
BWR	SS	RCPB	HF.Welding error	2	2									2	
BWR	SS	RCPB	HF:Welding Error	3	7	1				1	1			4	
BWR	SS	RCPB	HF.Welding error	6	1									1	
BWR	SS	RCPB	HF.Welding error	6	8		8								
BWR	SS	RCPB	Hot cracking	4	1									1	
BWR	SS	RCPB	IGSCC - Intergranular SCC	1	4		2			1				1	
BWR	SS	RCPB	IGSCC - Intergranular SCC	2	3						2			1	
BWR	SS	RCPB	IGSCC - Intergranular SCC	3	2						2				
BWR	SS	RCPB	IGSCC - Intergranular SCC	4	20	2	5			2	7			4	
BWR	SS	RCPB	IGSCC - Intergranular SCC	6	10		7			1	2				
BWR	SS	RCPB	IGSCC - Intergranular SCC	6	203	3	174			1	22			3	
BWR	SS	RCPB	Overpressurization	4	2	1						1			
BWR	SS	RCPB	Severe Overloading	4	1			1							
BWR	SS	RCPB	SICC - Strain-rate induced Corrosion Cracking	6	1		1								
BWR	SS	RCPB	TGSCC - Transgranular SCC	1	1	1									
BWR	SS	RCPB	TGSCC - Transgranular SCC	2	1		1								
BWR	SS	RCPB	TGSCC - Transgranular SCC	3	1									1	
BWR	SS	RCPB	Thermal Fatigue	2	2									2	
BWR	SS	RCPB	Thermal Fatigue	3	1									1	
BWR	SS	RCPB	Vibration-fatigue	1	3									3	
BWR	SS	RCPB	Vibration-Fatigue	2	42	2	1			4	2			33	
BWR	SS	RCPB	Vibration-Fatigue	3	4									4	
BWR	SS	RCPB	Vibration-fatigue	4	1									1	
BWR	SS	RCS-INSTR	ECSCC - External Chloride induced SCC	2	1		1								
BWR	SS	RCS-INSTR	ECSCC - External Chloride induced SCC	3	1		1								
BWR	SS	RCS-INSTR	HF:Welding error	2	2					1				1	
BWR	SS	RCS-INSTR	IGSCC - Intergranular SCC	4	2						1			1	
BWR	SS	RCS-INSTR	TGSCC - Transgranular SCC	1	2					1				1	
BWR	SS	RCS-INSTR	TGSCC - Transgranular SCC	2	1									1	
BWR	SS	SIR		0	1	1									
BWR	SS	SIR	Brittle fracture	5	4		4								
BWR	SS	SIR	Corrosion	3	1									1	
BWR	SS	SIR	Corrosion-fatigue	5	1									1	
BWR	SS	SIR	ECSCC - External Chloride induced SCC	1	1									1	
BWR	SS	SIR	ECSCC - External Chloride induced SCC	6	1		1								
BWR	SS	SIR	Erosion	2	2						1			1	
BWR	SS	SIR	Erosion	6	1										1
BWR	SS	SIR	FAC - Flow Accelerated Corrosion	2	4									4	
BWR	SS	SIR	FAC - Flow Accelerated Corrosion	3	4				1					2	1
BWR	SS	SIR	FAC - Flow Accelerated Corrosion	4	2						1				1
BWR	SS	SIR	Fatigue	1	1									1	
BWR	SS	SIR	Fatigue	2	1					1					
BWR	SS	SIR	Fatigue	5	1									1	
BWR	SS	SIR	Fatigue	6	1									1	
BWR	SS	SIR	HF.CONSTANST	2	2									2	
BWR	SS	SIR	HF.CONSTANST	3	1									1	
BWR	SS	SIR	HF.CONSTANST	4	1										1
BWR	SS	SIR	HF.CONSTANST	5	1									1	
BWR	SS	SIR	HF:Fabrication Error	6	2		2								
BWR	SS	SIR	HF.Fabrication Error	6	1		1								
BWR	SS	SIR	HF.Human error	1	1									1	
BWR	SS	SIR	HF:Human error	2	1									1	
BWR	SS	SIR	HF.Welding Error	2	2									2	
BWR	SS	SIR	HF.Welding Error	4	1								1		
BWR	SS	SIR	HF:Welding Error	5	10		9			1					
BWR	SS	SIR	HF.Welding Error	6	6	1	2					1		2	
BWR	SS	SIR	IGSCC - Intergranular SCC	2	3	1	1							1	

BWR	SS	SIR	IGSCC - Intergranular SCC	4	4	1					2			1	
BWR	SS	SIR	IGSCC - Intergranular SCC	5	64	2	51				6			5	
BWR	SS	SIR	IGSCC - Intergranular SCC	6	22		18				4				
BWR	SS	SIR	MIC - Microbiologically Induced Corrosion	5	1							1			
BWR	SS	SIR	Overpressurization	5	1							1			
BWR	SS	SIR	Overstressed	2	2									2	
BWR	SS	SIR	Severe overloading	2	2								1	1	
BWR	SS	SIR	Severe overloading	4	1									1	
BWR	SS	SIR	Severe overloading	6	1			1							
BWR	SS	SIR	TGSCC - Transgranular SCC	5	1					1					
BWR	SS	SIR	TGSCC - Transgranular SCC	6	1		1								
BWR	SS	SIR	Thermal fatigue	2	3									3	
BWR	SS	SIR	Thermal fatigue	5	3		3								
BWR	SS	SIR	Thermal fatigue	6	1		1								
BWR	SS	SIR	Thermal Fatigue - Cycling	5	2		1							1	
BWR	SS	SIR	Unreported	5	1									1	
BWR	SS	SIR	Vibration-Fatigue	0	2					2					
BWR	SS	SIR	Vibration-fatigue	1	6		1							5	
BWR	SS	SIR	Vibration-fatigue	2	27		2			1	1	1	1	21	
BWR	SS	SIR	Vibration-fatigue	3	3		1							2	
BWR	SS	SIR	Vibration-fatigue	4	2									2	
BWR	SS	SIR	Vibration-fatigue	5	1									1	
BWR	SS	SIR	Vibration-fatigue	6	1				1						
BWR	CS	STEAM	Corrosion	2	1									1	
BWR	CS	STEAM	ECSCC - External Chloride Induced SCC	1	1							1			
BWR	CS	STEAM	Erosion	3	1									1	
BWR	CS	STEAM	Erosion	4	1									1	
BWR	CS	STEAM	FAC - Flow Accelerated Corrosion	2	16						3	1		12	
BWR	CS	STEAM	FAC - Flow Accelerated Corrosion	3	7									6	1
BWR	CS	STEAM	FAC - Flow Accelerated Corrosion	4	3									3	
BWR	CS	STEAM	FAC - Flow Accelerated Corrosion	5	7									7	
BWR	CS	STEAM	FAC - Flow Accelerated Corrosion	6	1									1	
BWR	CS	STEAM	Fatigue	2	3					1			1	1	
BWR	CS	STEAM	HF:CONST/INST	2	1									1	
BWR	CS	STEAM	HF:CONST/INST	3	1									1	
BWR	CS	STEAM	HF:CONST/INST	4	1					1					
BWR	CS	STEAM	HF:REPAIR/MAINT	1	1								1		
BWR	CS	STEAM	HF:Welding error	2	2									2	
BWR	CS	STEAM	HF:Welding error	3	2									2	
BWR	CS	STEAM	HF:Welding error	5	1					1					
BWR	CS	STEAM	HF:Welding Error	6	1		1								
BWR	CS	STEAM	IGSCC - Intergranular SCC	6	1		1								
BWR	CS	STEAM	Overpressurization	2	1							1			
BWR	CS	STEAM	Severe overloading	4	1							1			
BWR	CS	STEAM	SICC - Strain-rate Induced Corrosion Cracking	5	1		1								
BWR	CS	STEAM	SICC - Strain-rate Induced Corrosion Cracking	6	3		3								
BWR	CS	STEAM	TGSCC - Transgranular SCC	1	10		4			2				4	
BWR	CS	STEAM	TGSCC - Transgranular SCC	2	2		1							1	
BWR	CS	STEAM	Thermal fatigue	2	1									1	
BWR	CS	STEAM	Thermal fatigue	3	1									1	
BWR	CS	STEAM	Thermal fatigue	6	1									1	
BWR	CS	STEAM	Vibration-Fatigue	1	2							1		1	
BWR	CS	STEAM	Vibration-fatigue	2	12					1	1	2	2	6	
BWR	CS	STEAM	Vibration-fatigue	3	2									2	
BWR	CS	STEAM	Vibration-Fatigue	5	1									1	
BWR	CS	STEAM	Water Hammer	5	1		1								
BWR	CS	STEAM	Water Hammer	6	1			1							

Appendix B

Haddam Neck	PWR	CS	2.25	4	Erosion	GL 89-08
CANDU	PWR	CS	4	4	Thermal Fatigue	Korean
CANDU	PWR	CS	4	4	Thermal Fatigue	Korean
CANDU	PWR	CS	4	4	Thermal Fatigue	Korean
CANDU	PWR	CS	4	4	Thermal Fatigue	Korean
Millstone Unit 3	PWR	CS	6	5	Erosion/Corrosion	IN 91-18
Arkansas Nuclear One Unit 2	PWR	CS	14	6	Erosion	IN 89-53
DC Cook Unit 2	PWR	CS	16	6	Erosion	Bulletin 79-13
DC Cook Unit 2	PWR	CS	16	6	Erosion	Bulletin 79-13
Fort Calhoun Station	PWR	CS	12	6	FAC	IN 97-84
Surry Unit 1	PWR	CS	30	6	Not yet determined	IN 81-04
Surry Unit 2	PWR	CS	18	6	Erosion/Corrosion	IN 86-106
Trojan 1	PWR	CS	14	6	Erosion	IN 87-36
Zion 1	PWR	CS	24	6	Human Factor	IN 82-25
FR (Framatome Reactors)	PWR	CS	10	6	Corrosion	Korean
FR (Framatome Reactors)	PWR	CS	28	6	Corrosion	Korean
Diablo Canyon Unit	PWR	CS			Thermal Fatigue	IN 92-20
Lovilsa Unit 1	PWR	CS			Erosion/Corrosion	IN 91-18
Sequoyah Unit 1	PWR	CS			Thermal Fatigue	IN 92-20
Surry Unit 1	PWR	CS			Erosion/Corrosion	IN 91-18
Wolf Creek	PWR	SS	0.25	1	Vibration	IN 89-07
KSNP Korean Standard Nuclear Power Plant	PWR	SS	0.375	1	Thermal Fatigue	Korean
Oconee Unit 3	PWR	SS	0.75	1	Mechanical Failure	IN 92-15
WH-3	PWR	SS	0.75	1	Flow Induced Vibration	Korean
WH-3	PWR	SS	0.75	1	Flow Induced Vibration	Korean
H.B. Robinson Unit 2	PWR	SS	2	3	SCC	IN 91-05
Oconee Unit 2	PWR	SS	2	3	Vibration	IN 97-46
Prairie Island Unit 2	PWR	SS	2	3	SCC	IN 91-05
WH-3	PWR	SS	2	3	Flow Induced Vibration	Korean
WH-3	PWR	SS	2	3	Flow Induced Vibration	Korean
WH-3	PWR	SS	2	3	Flow Induced Vibration	Korean
Crystal River Unit 3	PWR	SS	2.5	4	Fatigue	IN 82-09
Fort Calhoun Station	PWR	SS	3.5	4	SCC	IN 82-02
Maine Yankee	PWR	SS	3.5	4	SCC	IN 82-02
Maine Yankee	PWR	SS	3.5	4	SCC	IN 82-02
Maine Yankee	PWR	SS	3.5	4	SCC	IN 82-02
Maine Yankee	PWR	SS	3.5	4	SCC	IN 82-02
Maine Yankee	PWR	SS	3.5	4	SCC	IN 82-02
Maine Yankee	PWR	SS	3.5	4	SCC	IN 82-02
Ginna	PWR	SS	8	5	SCC	IE Circular76-06
Foreign	PWR	SS	8	5	Thermal Stress	Bulletin 88-08
Arkansas Nuclear One Unit 1	PWR	SS	10	6	SCC	IE Circular76-06
Oconee Unit 2	PWR	SS	24	6	Erosion	IN 82-22
Sequoyah Unit 1	PWR	SS	16	6	Fatigue	IN 95-11
Sequoyah Unit 2	PWR	SS	10	6	Human Factor	IN 97-19
Surry Unit 2	PWR	SS	10	6	SCC	IE Circular76-06
Palo Verde	PWR	SS	Var		Human Factor	Bulletin 79-03
San Onofre Unit 2	PWR	SS	Var		Human Factor	Bulletin 79-03
San Onofre Unit 3	PWR	SS	Var		Human Factor	Bulletin 79-03
TMI unit 1	PWR	SS	[illegible]		SCC	IN 79-19
TMI unit 1	PWR	SS	[illegible]		SCC	IN 79-19
TMI unit 1	PWR	SS	[illegible]		SCC	IN 79-19
TMI unit 1	PWR	SS	[illegible]		SCC	IN 79-19
TMI unit 1	PWR	SS	[illegible]		SCC	IN 79-19
Farley Unit 2	PWR	[illegible]	[illegible]			IN 88-01
Point Beach Unit 1	PWR					IN 99-19

Appendix B (cont.)

Plant	Type	Material	Diameter	Pipe Size Group	Failure Mechanism	Reference
Dresden Unit 2	BWR	CS	4	4	Human Factor	Bulletin 74-10
Nine Mile Point Unit 2	BWR	CS	8	5	Fatigue	Event 36016
Vermont Yankee	BWR	CS	12	6	SCC	IN 82-22
Cooper Station	BWR	SS	0.25	1	Vibration	IN 89-07
Pilgrim	BWR	SS	1	2	Corrosion	IN 85-34
Browns Ferry 3	BWR	SS	4	4	SCC	IN 84-41
Browns Ferry 3	BWR	SS	4	4	SCC	IN 84-41
Nine Mile Point Unit 1	BWR	SS	6	5	SCC	Bulletin 76-04
Dreseden Unit 2	BWR	SS	10	6	Thermal Fatigue	IN 75-01
Dreseden Unit 2	BWR	SS	10	6	Thermal Fatigue	IN 75-01
Dreseden Unit 2	BWR	SS	10	6	Thermal Fatigue	IN 75-01
Dreseden Unit 2	BWR	SS	10	6	Thermal Fatigue	IN 75-01
Dreseden Unit 2	BWR	SS	10	6	Thermal Fatigue	IN 75-01
Hatch Unit 1	BWR	SS	22	6	SCC	IN 83-02
Hatch Unit 1	BWR	SS	22	6	SCC	IN 83-02
Hatch Unit 1	BWR	SS	22	6	SCC	IN 83-02
Hatch Unit 1	BWR	SS	22	6	SCC	IN 83-02
Hatch Unit 1	BWR	SS	22	6	SCC	IN 83-02
Hatch Unit 1	BWR	SS	20	6	SCC	IN 83-02
Hatch Unit 1	BWR	SS	24	6	SCC	IN 83-02
Montecello	BWR	SS	22	6	SCC	IN 83-02
Montecello	BWR	SS	12	6	SCC	IN 83-02
Montecello	BWR	SS	12	6	SCC	IN 83-02
Montecello	BWR	SS	12	6	SCC	IN 83-02
Montecello	BWR	SS	12	6	SCC	IN 83-02
Montecello	BWR	SS	12	6	SCC	IN 83-02
Browns Ferry 1	BWR					IN 82-24
Dresden Unit 1	BWR				Freezing	IN 94-38

Highlighted plants were not used in the data analysis due to missing information.

Appendix C. Collapsed OPDE Database

Collapsed OPDE Raw Data as function of Pipe Size

Plant Type	Pipe Size Group (inches)	Resulting Number of Failures		
		CS	SS	CS+SS
PWR	0.0-1.0	154	544	698
	1.0-2.0	74	154	228
	2.0-4.0	78	75	153
	4.0-10.0	126	112	238
	> 10.0	93	126	219
	Total	*525*	*1011*	*1536*
BWR	0.0-1.0	118	257	375
	1.0-2.0	32	75	107
	2.0-4.0	32	227	259
	4.0-10.0	50	234	284
	> 10.0	39	291	330
	Total	*271*	*1084*	*1355*
PWR+BWR	0.0-1.0	272	801	1073
	1.0-2.0	106	229	335
	2.0-4.0	110	302	412
	4.0-10.0	176	346	522
	> 10.0	132	417	549
	Total	*796*	*2095*	*2891*

Collapsed OPDE Raw Data as function of Failure Mechanism

Plant Type	Failure Mechanism	Resulting Number of Failures		
		CS	SS	CS+SS
PWR	Corrosion	106	28	134
	FAC	119	121	240
	MIC	43	1	44
	Erosion	*96*	*12*	*108*
	Fatigue	92	501	593
	Human Factors	36	126	162
	Mechanical Failures	22	37	59
	SCC	5	169	174
	Water Hammer	0	2	2
	Misc	6	14	20
	Total	*525*	*1011*	*1536*
BWR	Corrosion	29	32	61
	FAC	58	63	121
	MIC	6	1	7
	Erosion	40	9	49
	Fatigue	71	225	296
	Human Factors	24	85	109
	Mechanical Failures	18	25	43
	SCC	19	624	643
	Water Hammer	2	1	3
	Misc	4	19	23
	Total	*271*	*1084*	*1355*
PWR+BWR	Corrosion	135	60	195
	FAC	177	184	361
	MIC	49	2	51
	Erosion	136	21	157
	Fatigue	163	726	889
	Human Factors	60	211	271
	Mechanical Failures	40	62	102
	SCC	24	793	817
	Water Hammer	2	3	5
	Misc	10	33	43
	Total	*796*	*2095*	*2891*

Appendix D - References

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25) Rossi, Charles E., Information Notice 91-05: INTERGRANULAR STRESS CORROSION CRACKING IN PRESSURIZED WATER REACTOR SAFETY INJECTION ACCUMULATOR NOZZLES, January 30, 1991.

26) Rossi, Charles E., Information Notice 92-15: FAILURE OF PRIMARY SYSTEM COMPRESSION FITTING, February 24, 1992.

27) Grimes, Brian K., Information Notice 93-20: THERMAL FATIGUE CRACKING OF FEEDWATER PIPING TO STEAM GENERATORS, March 24, 1993.

28) Knapp, Malcolm R., Information Notice 94-38: RESULTS OF A SPECIAL NRC INSPECTION AT DRESDEN NUCLEAR POWER STATION UNIT 1 FOLLOWING A RUPTURE OF SERVICE WATER INSIDE CONTAINMENT, May 27, 1994.

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30) Davis, John G., Information Notice 75-01: THROUGH-WALL CRACKS IN CORE SPRAY PIPING AT DRESDEN-2, January 31, 1975.

31) NRC Bulletin 76-04: CRACKS IN COLD WORKED PIPING AT BWR'S, March 30, 1976.

32) Thompson, Dudley, Circular 76-06: STRESS CORROSION CRACKS IN STAGNANT, LOW PRESSURE STAINLESS PIPING CONTAINING BORIC ACID SOLUTION AT PWR's, November 22, 1976.

33) NRC Bulletin 79-03: LONGITUDINAL WELD DEFECTS IN ASME SA -312 TYPE 304 STAINLESS STEEL, March 12, 1979.

34) NRC Bulletin 79-13: CRACKING IN FEEDWATER SYSTEM PIPING, June 25, 1979.

35) Moseley, Norman C., Information Notice 79-19: PIPE CRACKS IN STAGNANT BORATED WATER SYSTEMS AT PWR PLANTS, July 17, 1979.

36) NRC Information Notice No. 81-04: CRACKING IN MAIN STEAM LINES, February 27, 1981.

37) Sheron, Dr. Brian, Proposed Modifications to ECCS Analysis Requirements, Presentation at Penn State University, September 23, 2004.

38) NRC Document, 10 CFR 50.46 LOCA Frequency Document (Attachment).

CORRECTED

PP7028 Piping FAC Inspection Program

FAC INSPECTION PROGRAM RECORDS FOR 2005 REFUELING OUTAGE

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TAB I

2004-2005 Program Scope Memo
Vermont Yankee – Engineering Department

WBS Element:	**FAC Inspection Program**	Project Number:	
Title:	**Piping Flow Accelerated Corrosion (FAC) Inspection Program 2004 & 2005 Program Related Efforts**		
Department:	**Design Engineering – Mechanical / Structural**		
Owner:	**James Fitzpatrick**		
Backup:	**Thomas O'Connor**		
Procedure No. & Title:	**PP 7028**, Vermont Yankee Piping Flow Accelerated Corrosion Inspection Program**		

Detailed Scope of Project (Explanation): Engineering activities to support ongoing Inspection Program to provide a systematic approach to insure that Flow Accelerated Corrosion (FAC) does not lead to degradation of plant piping systems. Currently** Program Procedure PP 7028 controls engineering and inspection activities to predict, detect, monitor, and evaluate pipe wall thinning due to FAC. Activities include modeling of plant piping using the EPRI CHECWORKS code to predict susceptibility to FAC damage, selection of components for inspection, UT inspections of piping components, evaluation of data, trending, monitoring of industry events and best practices, participation in industry groups, and recommending future repairs and /or replacements prior to component failure.
** Expected to adopt a new ENN Standard Program Procedure ENN-DC-315 (which is currently under development with an accelerated development date of 6/30/04).

Expected Benefits (Justification): VY committed to have an effective piping FAC inspection program in response to GL 89-08.

Consequences of Deferral: Possible hazards to plant personnel, Loss of plant availability, unscheduled repairs, and deviation from previous regulatory commitments.

Duration of Program: Life of plant

2004 Key Deliverables or Milestones:	Completion Estimate
Complete Focused SA write up & generate appropriate corrective actions (coordinate activities with program standardization efforts).	6/18/04
Completion of RFO 24 documentation, write and issue RFO 2004 Inspection Report	7/23/04
Software QA on XP platform for CHECWORKS FAC module Version 1.0G	8/13/04
Issue 2005 RFO Outage Inspection Scope. Including Scoping worksheets.	9/1/04
Update Piping FAC susceptibility screening to account for piping and drawing updates. Include effects from NMWC, power uprate, & life extension.	8/13/04
Update piping Small Bore piping database and develop new priority logic for inspection scheduling.	10/01/04

1 of 4

2004 Key Deliverables or Milestones: - continued	Completion Estimate
Update CHECWORKS models using Version 1.0G with latest 2002 RFO & 2004 RFO Inspection data (*Note ideally results are to be used in determining the 2005 inspection scope, however schedule milestones override program logic.*)	12/31/04
Adoption of ENN-DC-315 ENN Standard FAC program Procedure to include all previous improvements identified Self Assessments.	10/31/04
Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry (EPRI CHUG) meetings, evaluation of industry events (industry awareness) for effects on VY, license renewal project input, and fleet support.	12/31/04

2005 Key Deliverables or Milestones:	
Perform Program Self Assessment (minimum once per cycle).	4/1/05
Conversion of CHECHWORKS1.0G models to SFA Version 2.1x	9/1/05
RFO 25 support	11/15/05
Completion of RFO 25 documentation, develop RFO 25 Outage Inspection Report	12/31/05
Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry (EPRI CHUG) meetings, evaluation of industry events (industry awareness) for effects on VY, and fleet support.	12/31/05

2006 Key Deliverables or Milestones:	
Issue 2005 Outage Inspection Report	1/15/06
Update SFA Predictive Models with 2005 RFO data.	4/15/06
Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry (EPRI CHUG) meetings, evaluation of industry events (industry awareness) for effects on VY, and fleet support.	12/31/06
Estimated Budget or Expenses:	**Amount/Hrs**
Captured in DE Mech./Structural Base Budget	N/A

Others Impacted By Project:	Estimated Hours
System Engineering	40
Engineering Support	
Reactor Engineering	
Design Engineering	
Fluid Systems Engineering	40
Electrical / I&C Engineering	
Mechanical / Structural Design	
Level 3 Fragnet: (Attached)	
Performance Indicators for FAC Program are contained in the Program Health Report (Attached)	

2004-2005 Piping FAC Inspe… …on Program Level 3 Fragnet

YEAR 2004 (2nd half) (Time Line from 6/01/04 to 12/31/04)

Task No.	Task Description	Preparer (HRS) Estimated	Reviewer (HRS) Estimated.	TOTAL (HRS) Estimated.	Est. Start	Est. Delivery / Completion Date
04-1	Complete Focused SA write up & generate appropriate corrective actions (coordinate activities with program standardization efforts).	20	10	30	6/1/04	6/18/04
04-2	Completion of RFO 24 documentation, write and issue RFO 2004 Inspection Report	60	30	90	6/14/04	7/23/04
04-3	Software QA on XP platform for CHECWORKS FAC module Version 1.0G	20	10	30	7/1/04	8/13/04
04-4	Update Piping FAC susceptibility screening to account for piping and drawing updates. Include effects from NMWC, power uprate, & life extension.	40	20	60	7/12/04	8/13/04
04-5	Update piping Small bore piping database and develop new priority logic for inspection scheduling.	40	20	60	9/6/04	10/01/04
04-6	Update CHECWORKS models using Version 1.0G with latest 2002 RFO & 2004 RFO Inspection data	160	80	240	8/23/04	12/31/04
04-7	Issue 2005 RFO Outage Inspection Scope. Including Scoping worksheets.	40	20	60	8/2/04	9/1/04
04-8	Development/adoption of ENN-DC-315 ENN Standard FAC program Procedure to include all previous improvements identified Self Assessments.	80	40	120	6/2/04	10/31/04
04-9	Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry (EPRI CHUG) meetings, evaluation of industry events (industry awareness) for effects on VY, LR project input, and fleet support.	160	40	200	6/1/04	12/31/04
TOTAL HRS	(From end of RFO 24 to December 31, 2004)	620	270	890		

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2004-2005 Piping FAC Inspe... on Program Level 3 Fragnet

YEAR 2005 (1/1/05 TO 12/31/05)

Task No.	Task Description	Preparer (HRS) Estimated	Reviewer (HRS) Estimated.	TOTAL (HRS) Estimated.	Est. Start	Est. Delivery / Completion Date
05-1	Perform Program Self Assessment (minimum once per cycle).	40	20	60	3/1/05	4/01/05
05-2	Conversion of CHECHWORKS 1.0G models to SFA Version 2.1x	360	180	540	4/1/05	9/01/05
05-3	RFO 25 Preparation & Outage Support	160	80	240	9/1/05	11/15/0504
05-4	Completion of RFO 25 documentation, develop RFO 25 Outage Inspection Report	60	30	90	11/15/05	12/31/05
05-5	Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry (EPRI CHUG) meetings, evaluation of industry events (industry awareness) for effects on VY, and fleet support.	40	20	60	1/01/05	12/31/05
Total Hrs				990		

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TAB 2

VY Piping FAC Inspection Program PP 7028 - 2005 Refueling Outage

Inspection Location Worksheets / Methods and Reasons for Component Selection

By: DC 3/1/05 Reviewed T.M.C 3/1/05

Note: Revised for VY and Industry Events and Operating Experience on 3/1/05

Piping components are selected for inspection during the 2004 refueling outage based on the following groupings and/or criteria.

Large Bore Piping

LA: Components selected from measured or apparent wear found in previous inspection results.

LB: Components ranked high for susceptibility from current CHECWORKS evaluation.

LC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.

LD: Components selected to calibrate the CHECWORKS models.

LE: Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system. (through the Systems Engineering Group).

LF: Engineering judgment / Other

LG: Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

Small Bore Piping

SA: Susceptible piping locations (groups of components) contained in the Small Bore Piping data base which have not received an initial inspection.

SB: Components selected from measured or apparent wear found in previous inspection results.

SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.

SD: Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system. (through the Systems Engineering Group).

SE: Engineering Judgment / Other.

SG: Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

Feedwater Heater Shells

No feedwater heater shell inspections will be performed during the 2005 RFO. All 10 of the feedwater heater shells have been replaced with FAC resistant materials.

LA: Large Bore Components selected(identified) from previous Inspection Results

From the 1995/1996/1998/1999/2001/2002/2004 Refueling Outage Inspections (Large Bore Piping) these components were identified as requiring future monitoring. The following components have either yet to be inspected as recommended, or the recommended inspection is in a future outage.

Inspect. No.	Loc. SK.	Component ID	Notes /Comments / Conclusions
96-18 96-19	001	FD13EL05 FD13SP06	1996 Report: calculated time to Tmin is 11.5 & 12 cycles based on a single measurement. The 2005 RFO is 6 cycles since the inspection. **UT inspect elbow and downstream pipe in 2008**
96-36	002	FD02SP05	1996 Report: calculated time to Tmin is 9.5 cycles based on a single measurement. The 2005 RFO is 6 cycles since the inspection. **UT inspect elbow and downstream pipe in 2007**
96-37	005	FD07SP01	1996 Report: calculated time to Tmin is 9.6 cycles based on a single measurement. The 2005 RFO is 6 cycles since the inspection. **UT inspect elbow and downstream pipe in 2007**
96-39	005	FD07SP02US	1996 Report: calculated time to Tmin is 10.5 cycles based on a single measurement. The 2005 RFO is 6 cycles since the inspection. **UT inspect elbow and downstream pipe in 2008**
98-05 98-07	005	FD07EL06 FD07EL07	1998 Report: calculated time to Tmin is 7.5 & 6.7cycles based on a single measurement. The 2005 RFO is 5 cycles since the inspection. Given no significant wear found in adjacent components (RSL =14.3 cycles on FD07SP07) defer inspection until RFO26. **UT inspect elbow FD07EL07& and downstream pipe FD07SP08 in 2007**
99-13	011	FD08EL04 FD08SP04	1999 Report: calculated time to Tmin is 7.9 & 12.5 cycles based on a single UT inspection. The 2005 RFO is 4 cycles since the inspection. **UT inspect elbow and downstream pipe in 2008**
99-16	011	FD08SP05	1999 Report: calculated time to Tmin is 6.1 cycles based on a single measurement. The 2005 RFO is 4 cycles since the inspection. **UT inspect elbow and downstream pipe in 2007**
99-25 99-26	008	FD14EL03 FD14SP03	1999 recommendation to inspect pipe at upstream counterbore in 2004. Given that the only low readings were at the pipe counterbore and that 2004 RFO work included replacement of both No.1 feedwater heaters located under the elbow. **UT inspect elbow FD14EL03 & pipe FD14SP03 in the 2005 RFO.**
99-32 99-33	017	FD04TE01(pipe cap) CND-Noz32-A	1999 Report: calculated time to Tmin is 6.2 & 6.8 cycles based on a single measurement. The 2005 RFO is 4 cycles since the inspection. **UT inspect elbow and downstream pipe in 2005**
99-35 99-36	019	FD06TE01(pipe cap) CND-Noz32-C	1999 Report: calculated time to Tmin is 9.6 & 8.5 cycles based on a single measurement. The 2005 RFO is 4 cycles since the inspection. **UT inspect elbow and downstream pipe in 2005**
02-08 02-09	016	FD16EL01 FD16SP02US	2002 recommendation to inspect the elbow in 2007 based on a single measurement. **Re-inspect elbow and downstream pipe in 2007 (3 cycles from 2002).**
04-03	001	FD01TE05	2004 recommendation to inspect tee in 2008 based on the default wear rate of 0.005 inch/cycle. **Re-inspect upstream elbow and tee in 2008.**
04-06	002	FD02RD01	2004 recommendation to re-inspect in 2011 based on the default wear rate of 0.005 inch/cycle. **Re-inspect reducer with downstream elbow and tee in 2007.**

1.A: Large Bore Components selected(identified) from previous Inspection Results –continued

Inspect. No.	Loc. SK.	Component ID	Notes /Comments / Conclusions
04-08	001	FD02TE01	2004 recommendation to inspect tee in 2007 based on the default wear rate of 0.005 inch/cycle. Actual point to point measurements from 1999 to 2004 indicate no wear. Given EPU operation, **re-inspect with upstream elbow and reducer in 2007.**
04-09	001	FD03SP01	2004 recommendation to inspect pipe section in 2011 based on a single inspection and the default wear rate of 0.005 inch/cycle. **Re-inspect in 2011.**
04-10	001	FD07SP02DS	2004 recommendation to inspect pipe section in 2008 based on a single inspection. **Re-inspect with downstream elbow in 2008.**
04-13	001	FD14EL03	2004 recommendation to inspect Row 13 pup piece to DS valve in 2008 is based on a single UT inspection. **Re-inspect in 2008.**
04-23	001	MSD9TE01 to MSD9TE08	2004 recommendation to inspect pipe section in 2010 due to localized wear directly under 2 lines. **Re-inspect in 2010.**
04-23	001	MSD9EL05	2004 recommendation to inspect pipe section in 2010 base on a single inspection. **Re-inspect in 2010.**

Turbine Cross-around Piping:

Previous Internal Visual UT & Repair History:

Line	Mat.	Year Replaced	Internal Visual =V, Internal Thickness =UT, Repairs Performed =R								
			RFO16 S1992	RFO17 F1993	RFO18 S1995	RFO19 F1996	RFO20 S1998	RFO21 F1999	RFO22 S2001	RFO23 F2002	S2004 RFO24
36"-A	GE**	1983		V	V	V	V				V
36"-B	GE**	1981	V	V	V	V	V	V			V
36"-C	GE**	1981	V	V	V		V				V
36"-D	GE**	1983		V	V		V				V
30"-A	P-22*	1985	V		V		V				
30"-B	C.S.	Original	V/UT/R	V/UT/R	V/UT/R	V/UT	V	V		V	
30"-C	P-22*	1993	V/UT/R								V
30"-D	P-22*	1985			V						V

** 36" straight pipe sections replaced with GE B50A242E, elbows on the B & C lines are original GE specification D50A67D, elbows on A &D lines are D50A67E (Tnom =0.625 inch).
* 30" A,B,C replaced with A691 CL22 (2-1/4Cr), Fittings A234 WP22. (Tnom. = 0.625 inch)
30" B remains GE B50A242D, fittings and GE D50A67D carbon steel (Tnom = 0.50 inch).

NOTE: Reference Dwg. No. 5920-6841 Sh. 1 of 2 needs to be updated with correct information. This will be performed during the EPU design change effort.

The HP turbine rotor was replaced in 2004. Internal visual inspection of all four 36"diameter lines was performed. An internal visual inspection of the 30"C line (first inspection since the 1993 replacement) and the 30" D line was performed.

2005 RFO based on increased flows and the possibility of different flow regimes in both the 36 & 30 inch piping, perform a visual inspection. LP turbine work in 2005 RFO may provide opportunity for access to the 30 " lines. As a minimum inspect (2) 36 inch lines and the carbon steel 30" B line.

LB: Large Bore Components Ranked High for Susceptibility from CHECWORKS Evaluation

The current CHECWORKS wear rate calculations contain inspection data up to the 1999 RFO and wear rate predictions are current to the 2001 RFO. The 2001 and 2002 RFO inspection data has been entered into the CHECWORKS database. However, updated wear rate calculations are not complete, and won't be in time to support the schedule date for issuing the inspection scope for the 2005 outage. Based on a review of the 2001 and 2002 RFO inspection data for components on the Feedwater, Condensate, and Heater Drain Systems, the CHECWORKS models still appear to over-predict actual wear. Nothing new or unanticipated was observed in either 2002 or 2004.

Feedwater System

Listed below are components which meet the following criteria:

a) negative time to Tmin from the predictive CHECWORKS runs which include Inspection data up to the 1999 RFO.
b) no inspections have been performed on these components or the corresponding components in a parallel train since the 1999 RFO.

Component ID	Location Sketch	Location	Notes
FD07EL05	005	TB FPR Elev. 241	Components on other train were inspected
FD07TE01 FD07EL11	006	T.B Heater Bay Elevs 228 & 248	Components on other train were inspected in 1998. Results indicate minimal wear. **After updating the CHECWORKs model with newer data, assess need for additional inspections in 2007 RFO.**
FD07EL12	006	T.B Heater Bay Elev. 248	Feedwater heater replacement occurred in 2004 RFO. Informal visual inspections of internals and cut pipe profile indicated a stable red oxide and no distinguishable wear pattern.
FD08TE01 FD08EL07	012	T.B Heater Bay Elevs 228 & 248	Intermediate components FD08EL06 & FD08SP08 were inspected in 1998. Results indicate minimal wear. **After updating CHECWORKs model with newer data, assess need for inspecting components on the train vs. these.**
FD08EL08	012	T.B Heater Bay Elev. 248	Feedwater heater replacement occurred in 2004 RFO. Informal visual inspections of internals and cut pipe profile indicated a stable red oxide and no distinguishable wear pattern.
FD15EL08	013	RX Steam Tunnel El. 266	Internal visual of elbow performed in 1996 during check valve replacement, no indication of wall loss at that time. Corresponding component on line 16"- FDW-14 was inspected in RFO24. **After updating CHECWORKs model with newer data, assess need for inspecting this component in 2007 RFO.**

LB: Large Bore Components Ranked High for Susceptibility from CHECWORKS Evaluation - continued

Condensate System

Only one component was identified as having a negative time to Tmin. This was CD30TE02DS, the downstream side of a 24x24x20 tee on the condensate header in the feed pump room. The CHECWORKS prediction for the downstream side of the tee has a small negative hrs relative to the remainder of the components in the system and relative to the upstream side of the same tee. Other tees on the same header have been previously inspected and show no significant wear. The CHECWORKS model includes UT data up to the 1999 RFO. The inspections on this system performed in 2001 indicate minimal wear. **Components CD30TE02 and CD30SP04 were inspected in 2004.** This data along with the 2001 inspection data will be input to CHECWORKS to better calibrate the model.

Moisture Separator Drains & Heater Drain System

No components identified as having negative times to Tmin. No components were selected for inspection in 2001, 2002, or 2004 based on high susceptibility. However future operation under HWC will change dissolved oxygen in system. A separate evaluation has been performed and components were selected for inspection in 2002. See Section LD below.

Extraction Steam System

Three components on this system with negative time to code min. wall: The piping is Chrome-Moly. ES4ATE01 & ES4ATE02, 30inch diameter tees inside the condenser have negative prediction (-3426Hrs.) for time to min wall. The negative times to tmin may be conservative based on the modeling techniques used. Refinement of the model of this system is in progress. The negative time to tmin is most likely a function of lack of inspection data vs. actual wear. Due to external lagging on this piping and the location inside the condenser, no components are selected for external UT inspection in 2004 based on high susceptibility. However, an opportunity to perform an internal visual inspection of all the Extraction Steam lines inside the condenser during planed LP turbine work in the 2005 RFO may present itself. See Section LF below.

Note the short section of straight pipe on line 12"-ES-1A at the connection to the 36 inch A cross around is assumed to be A106 Gr. B carbon steel is not modeled in CHECWORKS. This component was inspected in 2004 by external UT and an internal visual inspection from the 36" cross around line.

LC: Large Bore Components Identified by Industry Events/Experience.

Review of FAC related Large Bore Operating Experience (OE) and/or piping failures reported since April 2003

Date	Plant – Type	Description & Recommended Actions at VY
8/9/2004	Mihama 3 - PWR	OE19368/OE18895: Rupture of Condensate line downstream of restriction orifice. PWR system highly susceptible to single phase FAC due to low DO. Similar region of system as 1986 Surry event (5 fatalities). Based on info gathered by INPO/CHUG/FACnet the location was omitted from previous inspections due to clerical error, once discovered management missed opportunity to inspect and deferred inspection until 9/04. Too late. Lesson: make sure all highly susceptible locations get inspected. PWR Condensate/feedwater piping is much more susceptible to single phase FAC than BWR with O2 injection. Given that, previous inspection history, and condensate CHECWORKS modeling; inspect piping DS of all flow orifices in the higher temperature condensate system that have not been previously inspected in RFO25. **Inspect CD30FE01 / CD30EL11 / CD30SP02 in RFO25 (re-peat inspection from 1989). Also, inspect CD31FE01 / CD31EL04 / CD30SP04 in RFO25 (new inspection).**
10/17/03	Duane Arnold - BWR	OE17300: Through wall leak in 4" diameter chrome-moly Heater Drain System bypass line to the condenser. The line was a temporary installation due to delayed FWD heater installation. The cause of the leak appears to be droplet impingement erosion due to use of a bypass control valve. The equivalent lines at VY are the Heater Drain bypass lines to the condenser downstream of the high level control valves. These line have RTD's attached to monitor leakage into the condenser (TPM system). Some inspections have been performed on these lines. Consider for re-inspection only if TPM indicates leakage by the normally closed valves.
9/24/03	South Texas Project - PWR	OE17378: Pitting & internal wear found on discharge piping of Condensate Polishing System. Pipe is carbon steel, low water temperature (90 to 130F), neutral pH, and velocity of 12.2 Ft./sec Tortuous flow path and control valves, wear may be impingement. PWR system Low dissolved oxygen. Equivalent system at VY is Condensate Demineralizer System which is low temp and screens per NSAC-202L as not susceptible to FAC based on temperature. No OE on BWR systems.
11/07/03	Braidwood 2- PWR	OE17484: Wall thinning found on FDW pump discharge nozzles and extending into downstream pipes on all 3 FDW pumps. Material has high chromium content. PWR feedwater system chemistry has low D.O. therefore more susceptible to wall loss due to single phase FAC than BWR feedwater piping. At VY all three feedwater pump discharge nozzles and downstream piping have multiple inspection data. No further actions are anticipated from this OE.
10/31/03	Clinton -BWR	OE17412 / OE18478: Through-wall leaks in 2A/ B heater vent lines to the condenser (lager bore lines assumed given description of backing rings in piping). Apparent cause attributed to steam jet impingement from wet steam. Equivalent line at VY is common 4 inch feedwater heater vent line for No.4 FDW heaters. This line is included in the SSB database since it connects to (2) 2-1/2" lines. Inspection priority will be determined in the small bore ranking and prioritization.
11/19/03	Hope Creek – BWR	OE17700: Pinhole leak and wall thinning in 8" in carbon steel Extraction Steam supply line to Steam Seal Evaporator. Location of wear is downstream of pressure safety valves. Apparent Cause of leak & wear is due to liquid droplet impingement due to high flows from failure of pressure safety relief valves. No equivalent configuration at VY.
1/24/04	LaSalle 1 - BWR	OE17199 / OE18381: Tough-wall holes in extraction steam piping inside condenser. Location of holes at inlet nozzles to No.2 FDW heaters located in the neck of the condensers (2nd lowest stage). All 12 nozzle are C.S. with A335-P11 upstream piping. VY has only the No. 5 FDW heaters in the neck of the condenser. The No. 5 FDW heaters were replaced with Chromo-moly shells. ES piping is A335-P11 or equivalent which is FAC resistant. No further actions are anticipated from this OE.

LC: Large Bore Components Identified by Industry Events/Experience - continued

Date	Plant – Type	Description & Recommended Actions at VY
2/17/04	Peach Bottom 2 BWR	OE18637: On line leak in 10 inch main steam drain line header to the condenser. Hole was located directly below the connection of 1" main steam lead drain. The header was replaced with 1-1/4 Chrome material approx. 5 years before the leak. Also, ROs in steam drains were modified. The cause was attributed to steam impingement. Additional information to follow after next RFO. The only large bore drain collector at VY is the 8 inch diameter low point drain header, line 8"MSD-9. Flow is through steam traps and LCVs vs. a continuous flow through a restriction orifice. This line is now part of the AST ALT boundary. Inspections of the entire bottom of this header were performed during RFO24 with recommendations for repeat inspections in 2010.
8/26/04	Palo Verde 3-PWR	OE20386: Through wall leak found on a 10 inch flashing tee cap on the LP feedwater heater drains. Problems with inspection of flashing tees in program. Only 14 out of 153 susceptible locations have UT data at Palo Verde 1,2,3. There are no flashing tees D.S. of LCVs on the heater drain system at VY. The only flashing tees at VY are located on the FWD pump min flow lines at the condenser. **Inspection of all 3 lines 6"FDW-4, 6"FDW-5, and 6"FDW-6 is scheduled for RFO25.**
9/24/04	Palisades- PWR	OE19494: Wall thinning in carbon steel Extraction Steam piping. Increased localized wear downstream of Bleeder trip valve. Equivalent piping at VY is Extraction Steam piping downstream of the reverse current valves. ES piping at VY is A335-P11 which is FAC resistant. No further action is required for this OE.
9/18/04	Catawaba 2 – PWR	OE19350: Wall thinning found four different areas on FDW piping. Two areas are not considered specific to Catawba: 1)Area where main feedwater bypass reg valves reenters the feedwater header and 2) downstream of the main feedwater reg valves. PWR feedwater system chemistry has low D.O. therefore more susceptible to wall loss due to single phase FAC than BWR feedwater piping. At VY area 1) doses not exist (bypass lines dump to the condenser) 2) Inspections have been performed upstream and downstream of both main feed reg. valves. **Inspection of FD08RD03 and FD03SP02 are scheduled for RFO25. No further actions are anticipated from this OE.**
11/3/04	Duane Arnold - BWR	OE19701: Wall thinning downstream of Torus Cooling Test Return Header Isolation Valve. Apparent cause was cavitation erosion due to throttling in valve during HPCI & RCIC testing. At VY, the equivalent valves are V10-34A & 34B. The degree of cavitation present is dependent of the system design and may vary from plant to plant. Previous UT inspections were performed on valve bodies and downstream reducers in early 90s. No significant wear was found. **Consider inspection of downstream piping in RFO26 if additional OE warrants it.**
2/6/05	Calvert Cliffs 1 - PWR	OE20127: Through-wall leak in 6 inch steam vent header for MSR rain tank. VY does not have same configuration. No Moisture Separator Re-heaters
2/17/05	Clinton -BWR	OE20246: Catastrophic failure of turbine extraction steam line bellows inside condenser. Found through-wall holes ES piping DS of bellows due to FAC. Apparent cause was attributed to the steam jet from the holes inducing vibration of the expansion joint that led to high cycle fatigue failure. At VY extraction steam piping inside the condenser is A335-P11 or equivalent which is FAC resistant. No further actions are anticipated from this OE.
5/9/01	Grand Gulf - BWR	Pin Hole Leak in 4 inch carbon steel elbow in RHR min flow line. System has low use at VY (<2% of time). (Perry also found thinning at elbow per C.Burton at CHUG meeting.) A review of VY drawings VYI-RHR-Part 14 Sht.1/1 and VYI-RHR Part 15 Sht.1/1 show elbows downstream of restriction orifices. Previous VY Inspections downstream of orifices on HPCI/and CS systems found no problems. Keep OE listed for future consideration.

LC: Large Bore Components Identified by Industry Events/Experience - continued

Date	Plant – Type	Description & Recommended Actions at VY
9/24/02	IP2 - PWR	Pin hole leak on 26 ½" cross-under piping (HP to MSR) in vicinity of dog bones at expansion joint under location of weld overlay localized wear under/around a previous weld overlay repair. VY has solid piping (no expansion joints). **Visual Inspections of 30" B CAR carbon steel piping will be performed in 2005.**
1/15/02 CHUG Meeting	Surry 1-PWR	Leak in 8 inch Condenser drain header for 3rd/4th pt. FDW Heater vents. Also thinning in Gland Steam Piping inside the condenser and the12" Condenser Drain header from MS Drain trap lines. The only large bore drain collector at VY is the 8 inch diameter low point drain header, line 8"MSD-8. This line is now part of the AST ALT boundary. Inspections of selected components on this line were performed during RFO24 with recommendations for repeat inspections in 2010 (Section LB above). Given this line is part of the ALT Boundary **inspect approx. 2 ft. long section at condenser wall during RFO26 (2007) or RFO27 (2008).**

LD: Large Bore Components Selected to Calibrate CHECWORKS

The CHECWORKS models have been upgraded to include the 96, 98, & 99 RFO inspection data. The 2001 and 2002 inspection data has been loaded however wear rate analyses have not been completed at this time.

Condensate:

In 2001 components on the higher temperature end of the Condensate System were inspected to calibrate the CHECWORKS models. The inspection data indicate minimal wear and should reinforce the assessment of low wear in the Condensate System. Additional components selected for inspection in 2004 in Section LB above will be used to calibrate the CHECWORKS model.

Heater Drains/ Moisture Separator Drains:

Prior to the 2002 RFO there was limited inspection data for the Heater Drain system. The current CHECWORKS models (Pass 1 and some Pass 2) indicate low wear rates. During 2002 a number of new inspections were performed on the carbon steel piping upstream of the level control valves (LCV) to obtain a baseline prior to operation on hydrogen water chemistry. Piping down stream of the LCVs is FAC resistant material except for inlet to No.5 Feedwater heaters. No additional components on the Heater Drain system will be inspected in 2005.

Feedwater:

No inspections on line 18"-FDW-12 have been inspected: **Inspect FD12EL06 and FD12SP08US in 2005**

Main Steam

Only 2 components in the Main Steam system on line 18'MS-7A in the drywell have been inspected to date. **Inspect MS1DEL07 and MS1DSP13US in 2005.** (Note this also addresses a license renewal consideration for monitoring of Main Steam Piping).

LE: Large Bore Components subjected to off normal flow conditions identified by turbine performance monitoring system (Systems Engineering Group).

The Systems Engineering Production Variance Reports for 2003 listed the "B" and "C" feedwater pump min flow valves as leaking into the condenser. There are sections on carbon steel piping at the connection to the condenser on all three lines. **As a minimum inspect the "B" and "C" lines in 2005.**

There have been concerns with cavitation at condensate min flow valve FCV-4. An internal inspection of the valve performed in RFO 24 showed some damage to the valve internals. However, due to a leaking isolation valve the connecting piping was flooded and an internal visual inspection could not be performed. **UT inspect the upstream and downstream piping during RFO25.** The valve is operated during outages and startup at relatively low temperatures for FAC to occur. The piping is un-insulated and close to the floor. No insulation removal or scafolding will be required.

Since startup from 2004 (RFO24), no other leaking valves or steam traps have been identified (to date) using the Turbine Performance Monitoring (TPM) system. However, if new data indicates leaking valves then, additions to the outage scope may be required.

LF: Engineering Judgment / Other

Nine ASME Section XI Class 1 Category B-J welds are to be inspected by the FAC program per Code Case N-560 in lieu of a Section XI volumetric weld inspection. The VY ISI Program Interval 4 schedule for inspection of these welds is as follows:

Refueling Outage	Section XI ISI Program Weld ID	Description	FAC Program Components
Spring 2004 (RFO24) Interval 4 Period 1, Outage 1.	FW19-F3B FW19-F3C FW19-F4 FW21-F1	upstream pipe to tee tee to reducer reducer to pipe tee to pipe	"A" Feedwater on Sketch 010 FD19TE01 FD19RD01 FD19SP04 FD21SP01
Fall 2011 (RFO29) Interval 4 Period 3, Outage 6.	FW18-3A FW20-3A FW20-F1 FW20-F1B FW18-F4	upstream pipe to tee tee to reducer reducer to pipe horizontal pipe to pipe tee to pipe	"B" Feedwater on Sketch 016 FD18TE01 FD20RD01 FD20SP01 FD18SP04

Continued

LF: Engineering Judgment / Other –continued

Extended Power Uprate (EPU)

Feedwater system:

EPU evaluation for Feedwater System: The primary focus of work to date (for PUSAR and RAIs) was on velocity changes given only slight increases in temps and no chemistry changes. With all 3 FDW pumps running the 16 inch diameter lines to the 24 inch FDW header have approx. [1.2(2/3) ≈ 0.80] 20% reduction in velocity. Velocities in the remainder of the system increase approx. 20%. The highest velocities are at the 10 inch reducers upstream and downstream of the FDW REG valves. The expander and downstream piping have multiple inspection data with FD07RD03/FD07SP03 last inspected in 2001 and FD08RD03/FD08SP02 last inspected in 1999. ***Both of these segments should be re- inspected after some time of operation at EPU flows. Assuming EPU starting early in 2006,*** **inspect components FD08RD03 & FD08SP02 in 2005 to obtain an up to date pre-EPU measurement. Inspect FD07RD03 / FD07SP03 in 2007 for a post EPU measurement.**

Condensate System:

Given the 8/04 Mihama event: consider additional component in the condensate system for inspection : downstream of flow orifices & venturies:

FE-102-4 and downstream pipe on 24"C-8 venturi type (TB condensate pump room overhead) Given low operating temperatures and upstream of oxygen injection point, **scope out and evaluate for inspection in RFO26 in 2007**
FE-52-1A to FE-52.1E on Condensate De-mineralizer System (Restriction Orifices). Given low operating temperatures and upstream of oxygen injection point, **scope out and evaluate for inspection in RFO26 in 2007**
FE-102-7and downstream pipe on 14"C-21 venturi type TB Heater Bay El 237.5 Given low operating temperatures and used for start-up, **scope out and evaluate for inspection in RFO26 in 2007**
FE-102-2A on 20"C-30, located in the TB FPR above FDW pump 1A (venturi type) Previously inspected in 1989 **Re-Inspect FE and downstream piping in RFO25**
FE-102-2B on 20"C-31, located in the TB FPR above FDW pump 1B (venturi type) No previous inspection data. **Inspect FE and downstream piping in RFO25**
FE-102-2C on 20"C-32, located in the TB FPR above FDW pump 1C (venturi type) Previously inspected in 2001

All Extraction Steam piping is A335-P11, a 1-1/4 chrome material, except for a short carbon steel stub piece in line 12"-ES-1A at the connection to the 36" A cross around line. An internal visual inspection of this stub piece was performed with the cross around inspection in RFO24. Also an UT inspection of ES1ASP01 was performed in RFO24.

Extraction Steam piping in the condenser has external lagging which requires significant effort for removal when performing external UT inspections (plus there are significant staging costs). The piping is A335-P11. However an opportunity to perform an internal visual inspection of all the Extraction Steam lines inside the condenser during planed LP turbine work in the 2005 RFO may present itself.

LG: *Piping Identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)*

Word searches of open work orders on EMPAC were performed for the following keywords: trap, leak, valve, replace, repair, erosion, corrosion, steam, FAC, wear, hole, drain, and inspect. No previously unidentified components or piping were identified as requiring monitoring during the Fall 2005 RFO.

Note: the internal baffle plate in Condenser B for the AOG train tank return line to the condenser is to be replaced in RFO 25 (ER 04-1454/ ER 05-232 /ER 05-0274). Erosion on baffle plate is from condenser side (not piping side).

Internal visual inspection of LCV-103-3A-2 during RFO 24 indicated some type of casting flaw. The System Engineer suspects possible leaking by the normally closed valve. The downstream piping was last inspected in 1990. The line typically has no flow. *Re-evaluate using the Thermal Performance Monitoring System Data and consider inspection of downstream piping in RFO26.*

Through wall leak in the steam seal header supply line 1SSH4 discovered on 9/24/04 (CR-VTY-2004-02985). A temporary leak enclosure was installed and a planned permanent repair is scheduled for RFO25. The leaks are on the bottom of un-insulated piping upstream of the gland seal. Field inspection of the leak location shows that the piping at the leak sloping down to the gland seal, not sloping up to the seal a shown on the design drawings. UT data on the top of the piping near the leak shows full wall thickness. At this time, the exact mechanism which caused the leak is not known. Additional inspections to determine the extent of condition on the 3 other gland seal steam supply lines are required

Inspect the 90 degree elbow and approx. 2 ft. of downstream piping on lines 1SSH3, 1SSH4, 1SSH5, and 1SSH6 during RFO 25. Also based on industry OE and similar piping geometry, inspect 2 of the SPE lines (1SPE3 and 1SPE5 during RFO 25.

<u>Small Bore Piping</u>

SA: Susceptible piping locations (groups of components) contained in the Small Bore Piping data base which have not received an initial inspection.

Locations on the continuous FDW heater vents to the condenser on the No. 3 heaters were inspected in 2002. The continuous vents on the No. 4 heater were installed new in 1995. The start up vents operate less than 2% of operating time. No wear was found in previous inspections on Heater Vent piping from the No.1 & 2 heaters. Given that and the lower pressure in the No. 4, shells a complete inspection of the remainder of the No. 4 heater vent piping can be deferred. The existing small bore date base and the piping susceptibility analysis is under revision. No additional components from Revision 1 of the data base will be inspected.

SB: Components selected from measured or apparent wear found in previous inspection results.

Small Bore Point No. 20. 2-1/2" MSD-6 @ connection to condenser A at Nozzle 33 (Inspection No. 96-SB01 identified a low reading at weld on stub to condenser). Upstream valves are normally closed. TPM system does not indicate any abnormal flow. **Inspect this piping in RFO 26**

A through wall leak in the turbine bypass valve chest 1st seal leak-off line form the No. 1 bypass vales occurred in 2003. (VY Event Report 2003-044). A temporary leak enclosure was installed (T.M.2003-002) to contain the leak). W.O. 03-0364 was written to inspect/repair/replace/line. A localized like-for-like (carbon steel) replacement of the leak location was performed in RFO 24. Additional inspections on this line identified localized wall loss and one additional like-for-like repair was performed. Engineering Request ER 04-0963 was written to completely replace this piping with chrome-moly piping. (Dresden has already done this). **The replacement (ER 04-0964) is currently scheduled for RFO 25. If this activity gets "de-scoped" then, additional inspections will be required to insure the piping is acceptable for continued operation.**

Small Bore Piping

SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.

Date	Plant – Type	Description & Recommended Actions at VY
11/7/2003	Limerick 1, BWR	OE17818: Through wall leak in 1 inch drain line back to condenser off ES piping at the connection to the large bore line. Normally no flow in line due to N.C. valve. Piping downstream of valves to condenser on all 3 lines was scheduled for replacement. Location US of valve was thought not to be susceptible. ES piping at VY is FAC resistant A335-P11 with no drains back to the condenser. Lesson from this event is any carbon steel line in a wet steam system is susceptible & should be monitored. Also full line replacement insures all susceptible piping is replaced.
1/16/04	Clinton – BWR	OE17654: Potential tend for adverse equipment condition downstream of orifices. (Ref. Previous experience a Clinton with CRD pump min flow ROs) Inspect CRD pump min flow orifices also piping DS of RO-64-2 in RFO25
12/06/04	V.C. Summer - PWR	OE19798: Complete failure of a 1 inch ES line at the location of a previously installed Fermanite clamp repair. Previous leak at weld installed in MAY 2004. See presentation at January 2005 CHUG meeting. (They did not do UT on the pipe to assure structural integrity prior to installing the clamp.)
3/1/05	McGuire 2- PWR	Though-wall leak in a 2 inch carbon steel vent line on the MSR heating steam vent line. Caused by FAC when flashing occurred upstream of RO (design location) No MSRS or equivalent location at VY.
4/29/99	Darlington 1 - PHWR	Severed line at steam trap discharge pipe at threaded connection. Equivalent to HHS system at VY. (INPO Event 931-990429-1) Threaded connections typically on condensate side of HHS piping. Lower energy/consequence of leak. Include HHS piping in FAC Susceptibility Review, and in the Small Bore Database. Include ranking and consequences of failure.
6/14/99	Darlington 2 - PHWR	Leak on steam trap discharge pipe at threaded connection. Equivalent to HHS system at VY. (INPO Event 932-990614-1) Same as above.
9/1/01	Peach Bottom 3 -BWR	(From 1/14/02 CHUG Meeting); leak on 1 inch Sch. 80 line from in Off Gas Re-combiner pre-heater drain line to condenser. Perform additional review of AOG steam supply system and incorporate into FAC Susceptibility Review. Update small bore database to include ranking and consequences of failure.
1/15//02 CHUG Mtg.	Hatch1/2 -BWR	Condenser in leakage due to through wall erosion (external) of 1-1/2 inch "slop" drains lines inside the condenser. Lines in each unit were cut and capped similar events at Byron Unit 1 (OE 12609) and Columbia (OE12145). Limerick & Dresden. VY slop drain lines inside condenser were walked down during RFO24. Some external erosion on piping and supports was found.
1/15/02 CHUG Mtg.	Catawba 2 - PWR	Leak in HP turbine pocket shell drain 1 inch dia. OEM showed pipe as P-11. However, A-106 Gr. B was installed. Inspections were be performed on this line in 2004 to base line condition prior to HP turbine rotor replacement.
1/15/02 CHUG Mtg.	Dresden 2 BWR	Thinning found in Bypass valve leak-off line to the 7[th] stage extraction steam line. Line is 2" Sch. 80, GE B4A39B. Lowest reading was 0.070" found using Phosphor Plate radiography. Line was replaced with A335 P-11. Same line as 2003 VY through wall leak. Partial CS replacement was performed in RFO24. Piping is scheduled to be replaced with A335-P11 in RFO25 (ER 04-0965).

<u>*Small Bore Piping*</u>

SD: Components subjected to off normal flow conditions, as indicated from the turbine performance monitoring system (Systems Engineering Group).

No small bore lines have been identified by Systems Engineering on or before 3/1/05.

SE: Engineering judgment

Look at piping DS of orifices based on BWR OE

Condensate: Given the 8/04 Mihama event: consider additional component in the condensate system for inspection downstream of flow orifices & venturies.

FE-102-6 and downstream pipe on 21/2"C-43 venturi type (TB heater bay elev. 230+/- Given low operating temperatures and *upstream of oxygen injection point*, ***scope out and evaluate for inspection in R26 in 2007***

SG: Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

See LG above. The EMPAC search performed in LG above is applicable to both Large and Small components.

MEMORANDUM

Vermont Yankee Design Engineering

TAB 3

To S.D.Goodwin Date May 5, 2005 *

From James Fitzpatrick File # VYM 2004/007a

Subject Piping FAC Inspection Scope for the 2005 Refueling Outage (Revision 1a)

REFERENCES

(a) *PP 7028 Piping Flow Accelerated Corrosion Inspection Program, LPC 1, 12/6/2001.*
(b) V.Y. Piping F.A.C. Inspection Program - 1996 Refueling Outage Inspection Report, March 23,1999.
(c) V.Y. Piping F.A.C. Inspection Program - 1998 Refueling Outage Inspection Report, April 2,1999.
(d) V.Y. Piping F.A.C. Inspection Program - 1999 Refueling Outage Inspection Report, February 11, 2000.
(e) V.Y. Piping F.A.C. Inspection Program - 2001 Refueling Outage Inspection Report, August 11,2001.
(f) V.Y. Piping F.A.C. Inspection Program - 2002 Refueling Outage Inspection Report, January 20, 2003.
(g) V.Y. Piping F.A.C. Inspection Program - 2004 Refueling Outage Inspection Report, February 15, 2005

(h) DISCUSSION

Attached please find the Piping FAC Inspection Scope for the 2005 Refueling Outage. The scope includes locations identified using: previous inspection results, the CHECWORKS models, industry and plant operating experience, input from the Turbine Performance Monitoring System, the CHECWORKS study performed to postulate affects of Hydrogen Water Chemistry operation on FAC wear rates in plant piping, and engineering judgment.

The planned 2005 RFO inspection scope consists of 37 large bore components at 16 locations, internal inspection of three legs of the turbine cross around piping, and 5 sections of small bore piping. Also, any industry or plant events that occur in the interim may necessitate an increase in the planned scope.

I will be available to support planning and inspections as necessary. If you have any questions or need additional information please contact me.

(Revision 1 identifies Small Bore Inspections due to Industry OE).
*(Revision 1a adds component Nos. to SSH & SPE piping & corrects minor typos in Attachment)

James C. Fitzpatrick
Design Engineering
Mechanical/Structural Group

ATTACHMENT: 2005 RFO FAC Inspection Scope 3/11/05 (3 Pgs) **Revised 5/5/05**

CC L.Lukens Code Programs Supervisor
D.King (ISI)
T.M.OConnor (Design Engineering)
Neil Fales (Systems Engineering)

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NEC037118

ATTACHMENT to VYM 2004/007a

VERMONT YANKEE PIPING FAC INSPECTION PROGRAM 2005 INSPECTION SCOPE (5/5/05)

LARGE BORE PIPING: External UT Inspections

Point No.	Component ID	Location Sketch	Location	Previous Inspections	Reason / Comments / Notes
2005-01	FD14EL03	008	T.B. Htr. Bay Elev. 267.	1999	1999 recommendation for repeat inspection.
2005-02	FD14SP03US	008	" " "	1999	
2005-03	FD04RD01	017	T.B. Htr. Bay Elev. 245.	1999	Inspect per 1999 calculated wear rate.
2005-04	FD04TE01	017	" " "	1999	
2005-05	Cond Noz 32A	017	" " "	1999	
2005-06	FD05RD01	018	T.B. Htr. Bay Elev. 245.	1993	TPM system indicated leakage by normally closed valve.
2005-07	FD05 TE01	018	" " "	1993	
2005-08	Cond Noz 32B	018	" " "	1993	
2005-09	FD06RD01	019	T.B. Htr. Bay Elev. 245.	1999	Inspect per 1999 calculated wear rate. Also, TPM system indicated leakage by normally closed valve.
2005-10	FD06TE01	019	" " "	1999	
2005-11	Cond Noz 32C	019	" " "	1999	
2005-12	FD08RD03	011	T.B. FPR Elev. 231	1999	EPU flows increase
2005-13	FD08SP02	011	" " "	1999	
2005-14	FD12EL06	007	T.B. Htr. Bay Elev. 264.	NO	Checworks Model Calibration. Asbestos removal required.
2005-15	FD12SP08US	007	" " "	NO	
2005-16	CD30FE01	037	T.B. FPR Elev. 241 above "A" FDW pump	1989	FE-102-2A (Mihama Event)
2005-17	CD30EL11	037		1989	
2005-18	CD30SP12	037		1989	

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ATTACHMENT to VYM 2004/007a

Point No.	Component ID	Location Sketch	Location	Previous Inspections	Reason / Comments / Notes
2005-19	CD31FE01	038	T.B. FPR Elev. 241 above "B" FDW pump	NO	FE-102-2B (Mihama Event) Asbestos removal required.
2005-20	CD31EL04	038		NO	
2005-21	CD31SP04	038		NO	
2005-22	CD21RD02	040	T.B. Htr. Bay Elev. 230.	NO	Inspect piping upstream and downstream of FCV-102-4 (piping is not insulated).
2005-23	CD21RD01	040	" " "	NO	
2005-24	1SSH3EL05	*	Turbine deck at packing 3 Htr. Bay Elev. 254.	NO	LP Turbine Steam Seal supply lines due to through wall leak at elbow on line 1SSH4. *See markup of Dwg. 5920-1239
2005-25	1SSH3SP06US	*			
2005-26	1SSH4EL01	*	Turbine deck at packing 4 Htr. Bay Elev. 254.	NO	
2005-27	1SSH4SP02US	*			
2005-28	1SSH5EL01	*	Turbine deck at packing 5 Htr. Bay Elev. 254.	NO	
2005-29	1SSH5SP02US	*			
2005-30	1SSH6EL06	*	Turbine deck at packing 6 Htr. Bay Elev. 254.	NO	
2005-31	1SSH6SP08US	*			
2005-32	2SPE3EL01	*	Turbine deck at packing 3 Htr. Bay Elev. 254.	NO	LP Turbine SteamPacking Exhaust at packing 3 and 5 due to through wall leak at elbow on line 1SSH4. *See Markup of Dwg. 5920-1239
2005-33	2SPE3SP01US	*			
2005-34	2SPE5EL01	*	Turbine deck at packing 5 Htr. Bay Elev. 254.	NO	
2005-35	2SPE5SP01US	*			
2005-36	MS1DEL07	080	RX Stm Tunnel Elev. 254 to 260	NO	EPU and LR data required for Main Steam lines.
2005-37	MS1DSP13US	080		NO	

LARGE BORE UT NOTES:
1. Coordinate minimum extent of insulation to be removed with J.Fitzpatrick or T.M. O'Connor from DE-M/S.
2. A "No" in the previous inspection column indicates asbestos abatement may be required.

LARGE BORE PIPING: Internal Visual Inspections (with supplemental UT as required

Inspection Point No.	Description
2005-38	36" CAR A (36 inch diameter Line A Turbine Cross Around under HP turbine)
2005-39	36" CAR C (36 inch diameter Line C Turbine Cross Around under HP turbine)
2005-40	30" CAR B (30 inch diameter Line B Turbine Cross Around upper east side of heater bay)

SMALL BORE PIPING

Small Bore Inspection Number	S.B. Data Base No.	System	Description	Location	Drawings	Reason /Comments
05-SB01	119	Condensate	1" piping DS of R.O. 64-2	T.B. Heater Bay	G191157 Sht.1 5920- FSI -17	Industry OE17654
05-SB02	128	CRD	1" Piping D.S. of R.O.-3-24A	Rx. SW Elev. 232.5 P38-1A	G191170 / G191212 / G191215	Industry OE17654
05-SB03	129	CRD	1" Piping D.S. of R.O.-3-25A	Rx. SW Elev. 232.5 P38-1A	G191170 / G191212 / G191215	Industry OE17654
05-SB04	130	CRD	1" Piping D.S. of R.O.-3-24B	Rx. SW Elev. 232.5 P38-1B	G191170 / G191212 / G191215	Industry OE17654
05-SB05	131	CRD	1" Piping D.S. of R.O.-3-25B	Rx. SW Elev. 232.5 P38-1B	G191170 / G191212 / G191215	Industry OE17654

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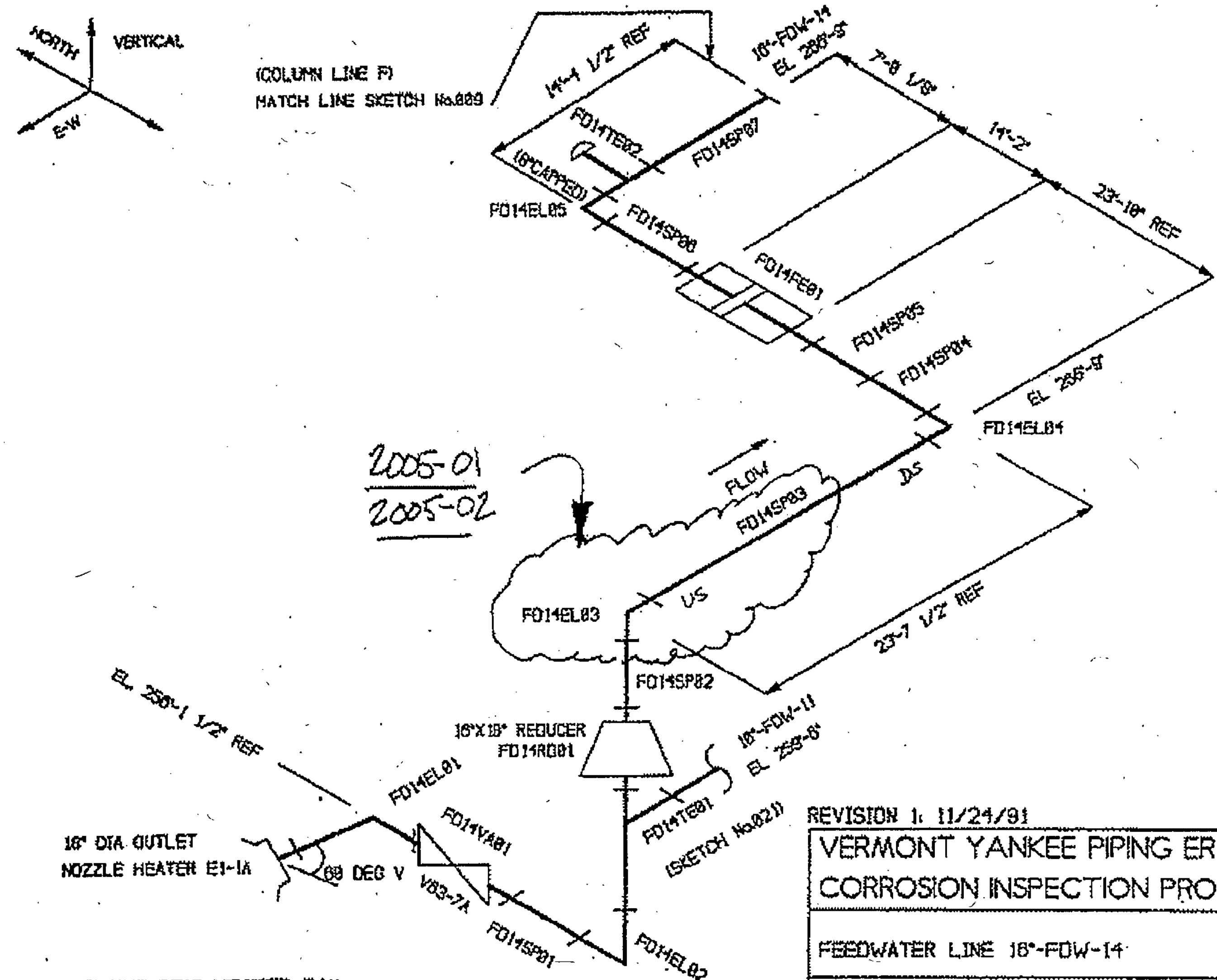

TURBINE BUILDING-HEATER BAY
REFERENCES: G191157,G191182,G191183,5920-FS-125

REVISION 1: 11/24/91

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

FEEDWATER LINE 16"-FDW-14

COMPONENT LOCATION SKETCH No.008

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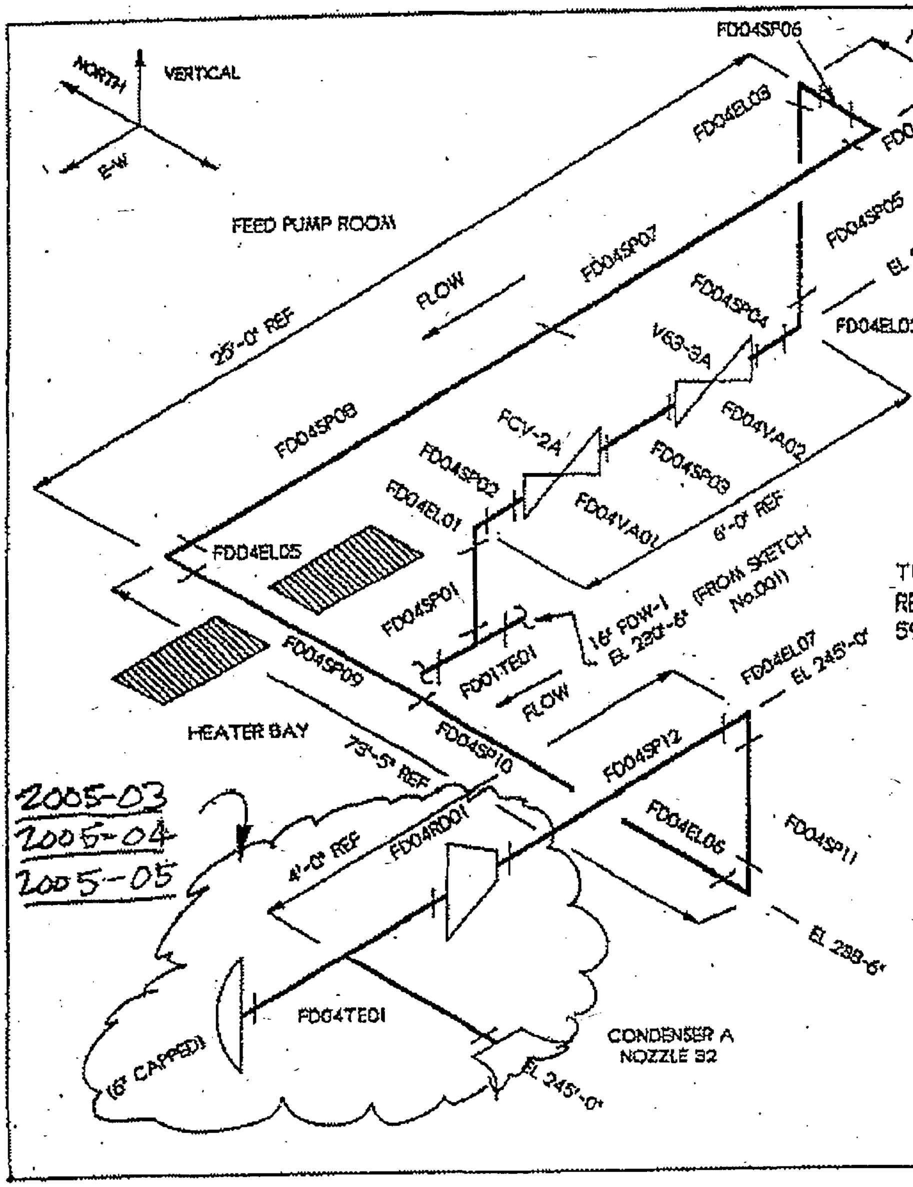

TURBINE BUILDING-FEED PUMP ROOM/HEATER BAY
REFERENCES: G191157,G191182,G191163
5950-FS-124,5920-FS-125

REVISION 1: 11/24/91

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

FEEDWATER LINE 4"-FDW-4

COMPONENT LOCATION SKETCH No.017

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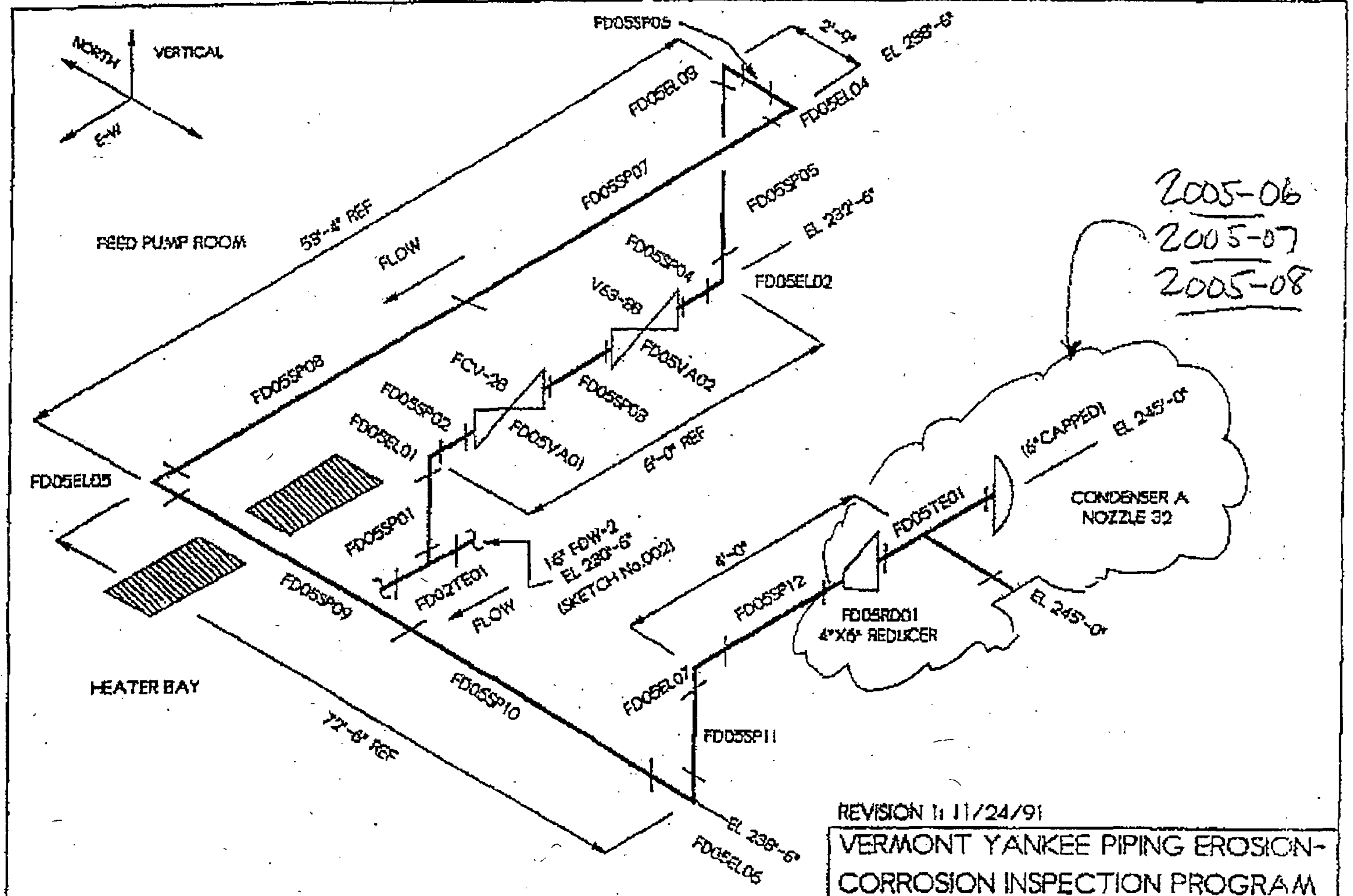

REVISION 1: 11/24/91

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

FEEDWATER LINE 4"-FDW-5

COMPONENT LOCATION SKETCH No.018

TURBINE BUILDING-FEED PUMP ROOM/HEATER BAY
REFERENCES: G191157,G191182,G191183
5950-FS-124,5920-FS-125

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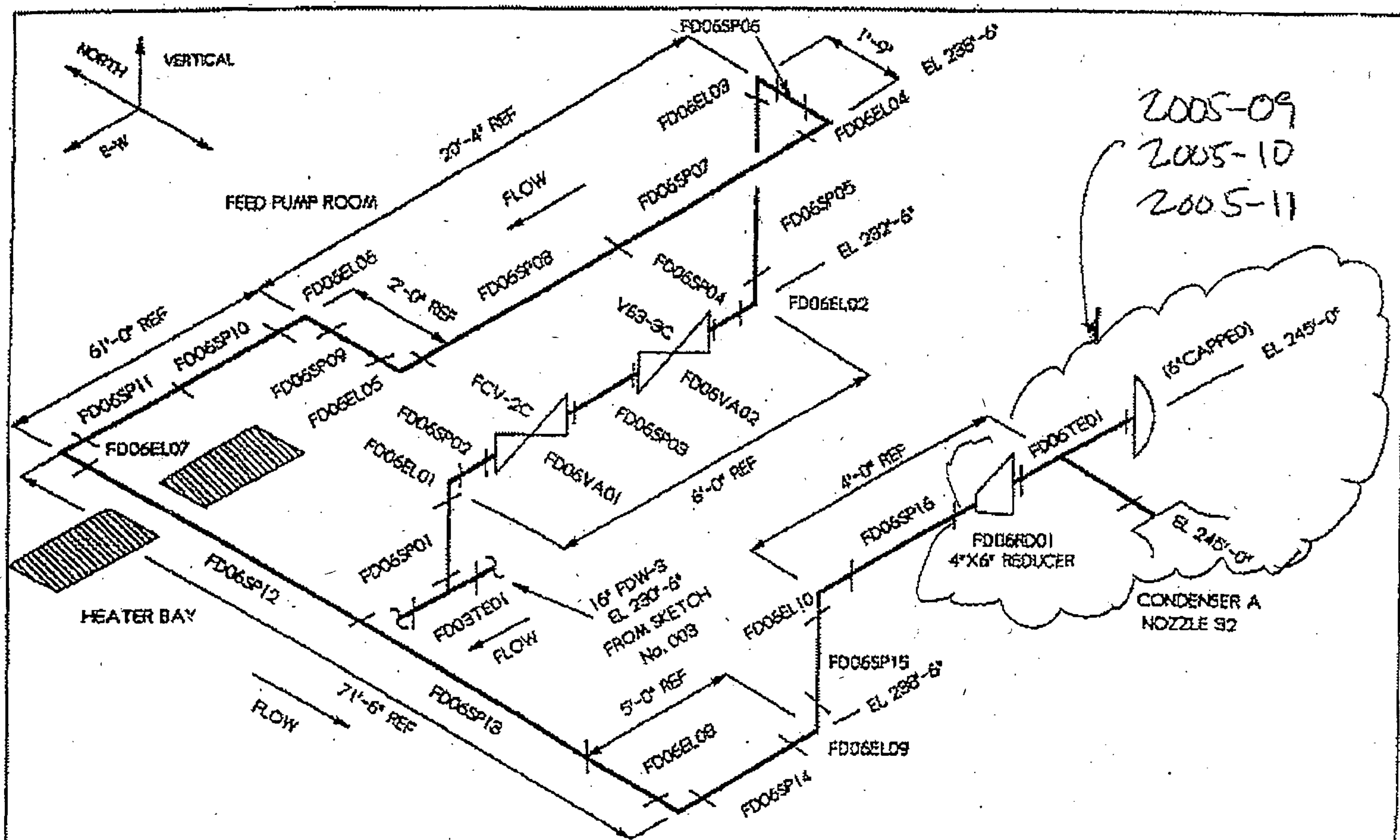
NEC037125



REVISION 1: 11/25/91

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

FEEDWATER LINE 4"-FDW-6

COMPONENT LOCATION SKETCH No.019

TURBINE BUILDING-FEED PUMP ROOM/HEATER BAY
REFERENCES: G191157,G191182,G191183
5950-FS-124,5920-FS-125

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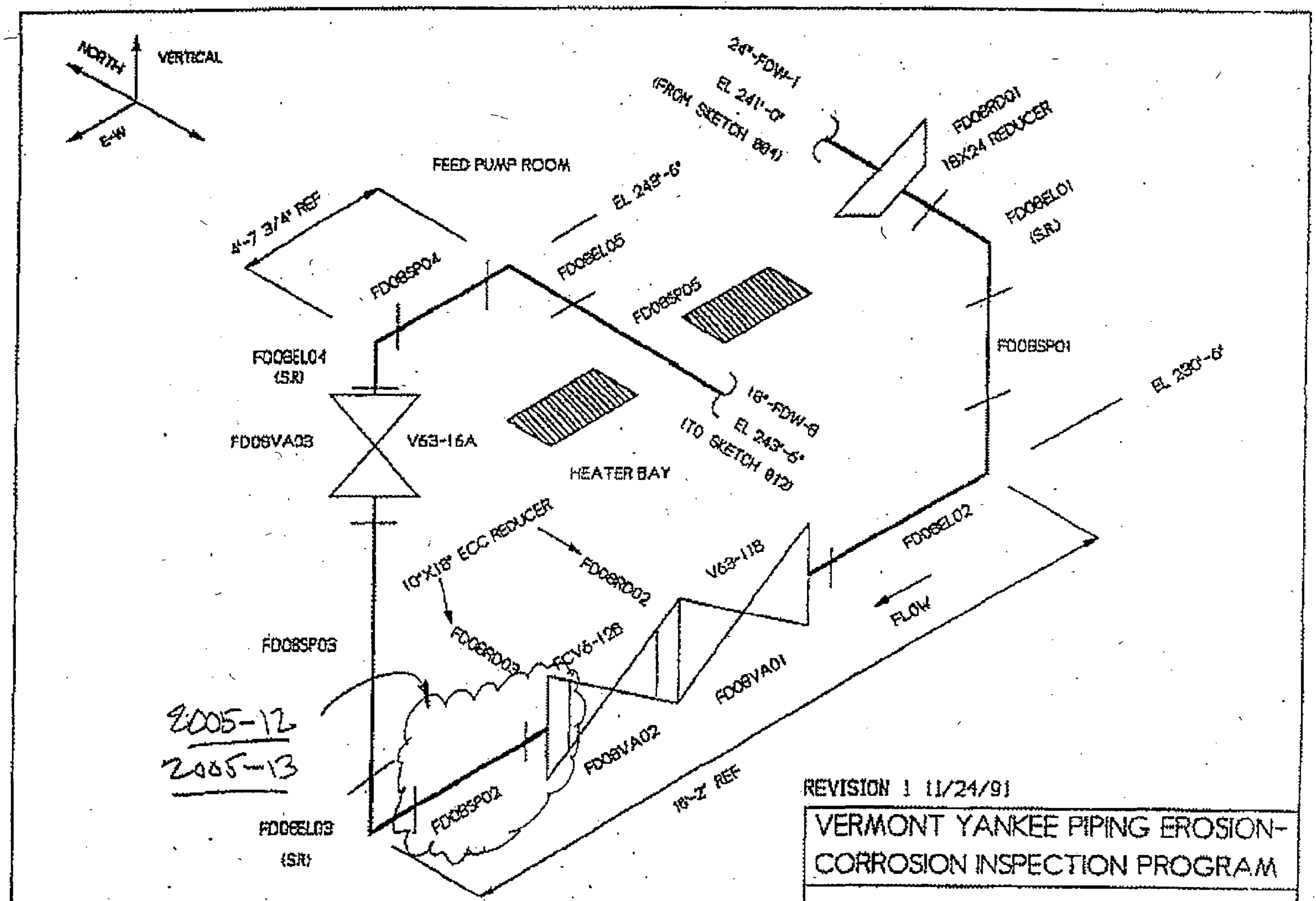
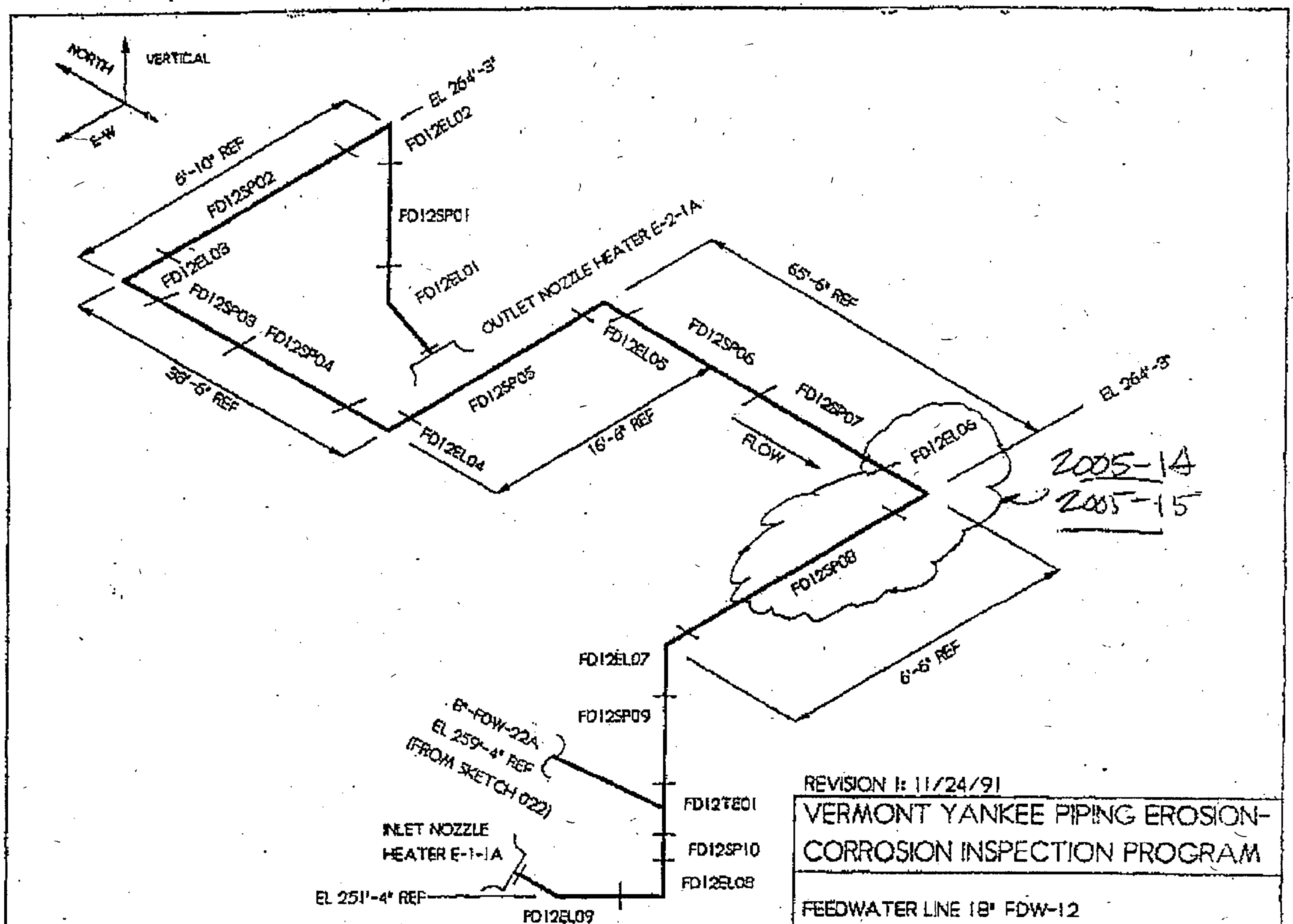


TURBINE BUILDING-FEED PUMP ROOM
REFERENCES: G191157,G191182,G191183,5920-FS-124

REVISION 1 11/24/91

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM
FEEDWATER LINE 18"-FDW-8
COMPONENT LOCATION SKETCH No.011

9 of 18



TURBINE BUILDING-HEATER BAY
REFERENCES: G191157,G191182,G191183,5920-FS-125

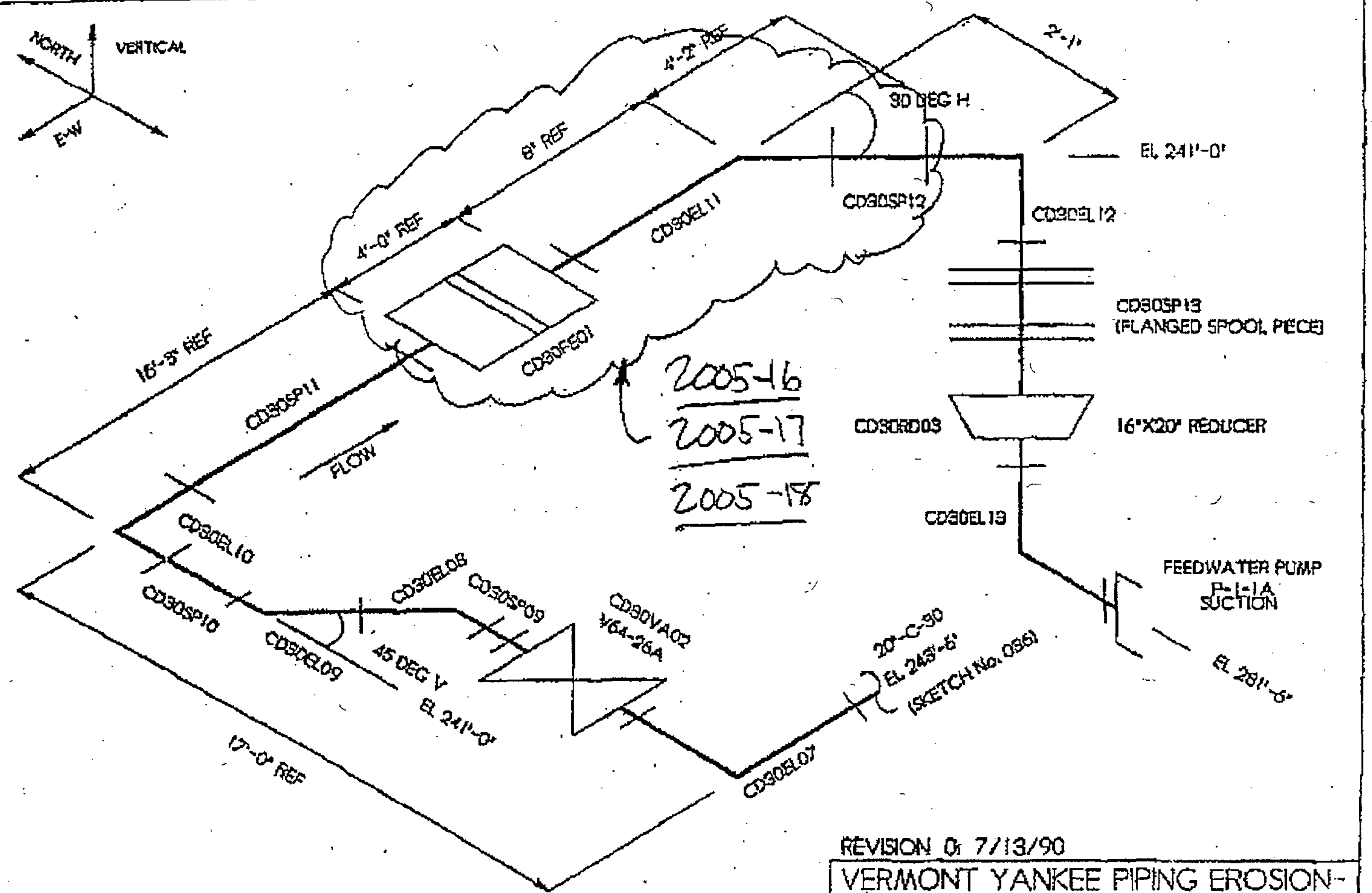
REVISION 1: 11/24/91

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

FEEDWATER LINE 18" FDW-12

COMPONENT LOCATION SKETCH No.007

ID of 18



REVISION 0: 7/13/90

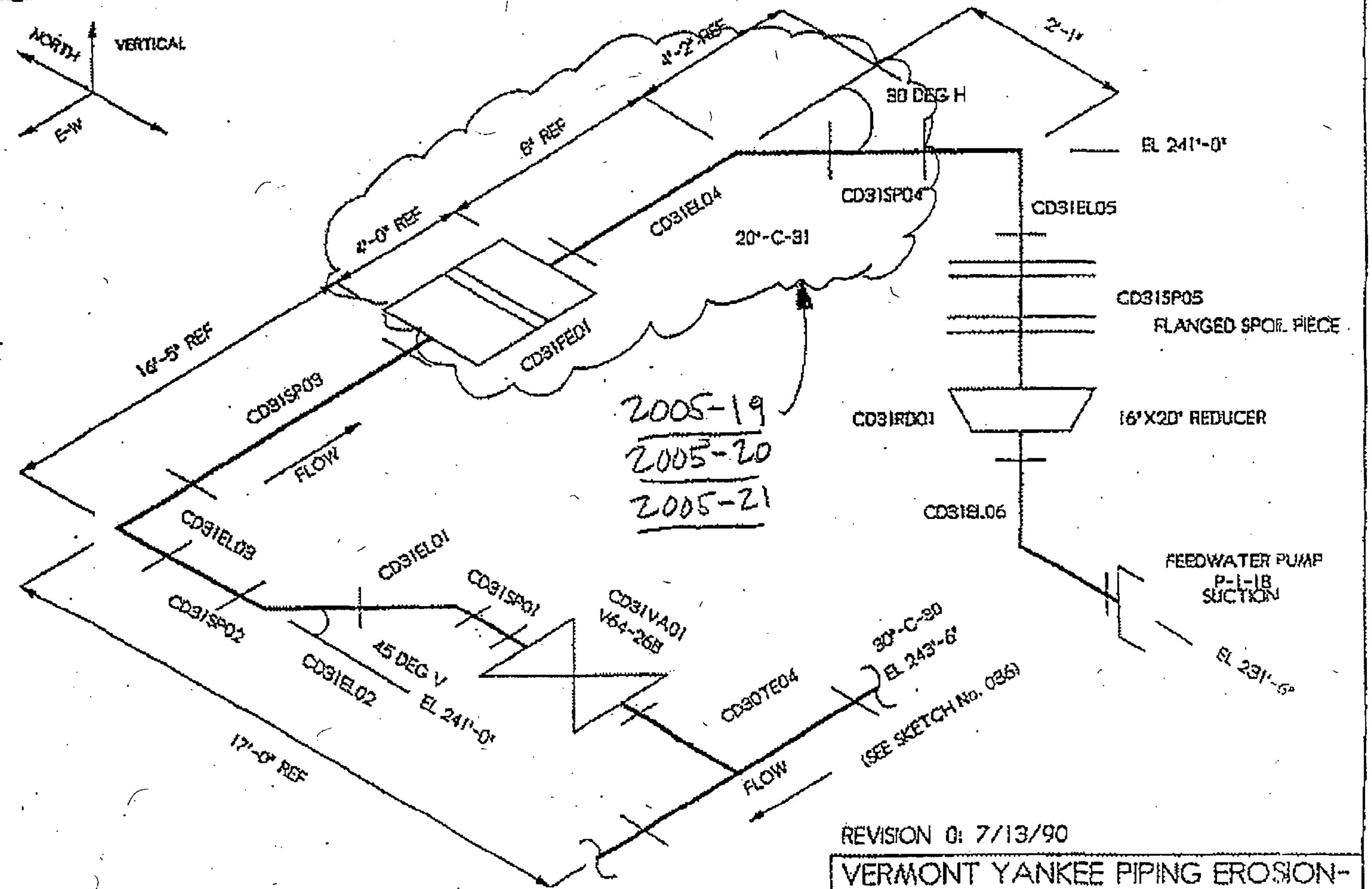
VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

CONDENSATE LINE 20"-C-30 (CONTINUED)

COMPONENT LOCATION SKETCH No. 037

TURBINE BUILDING-FEEDWATER PUMP ROOM
REFERENCES: G191157,G191186,G191187,5920-FS-116

8/20/11



REVISION 0: 7/13/90

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

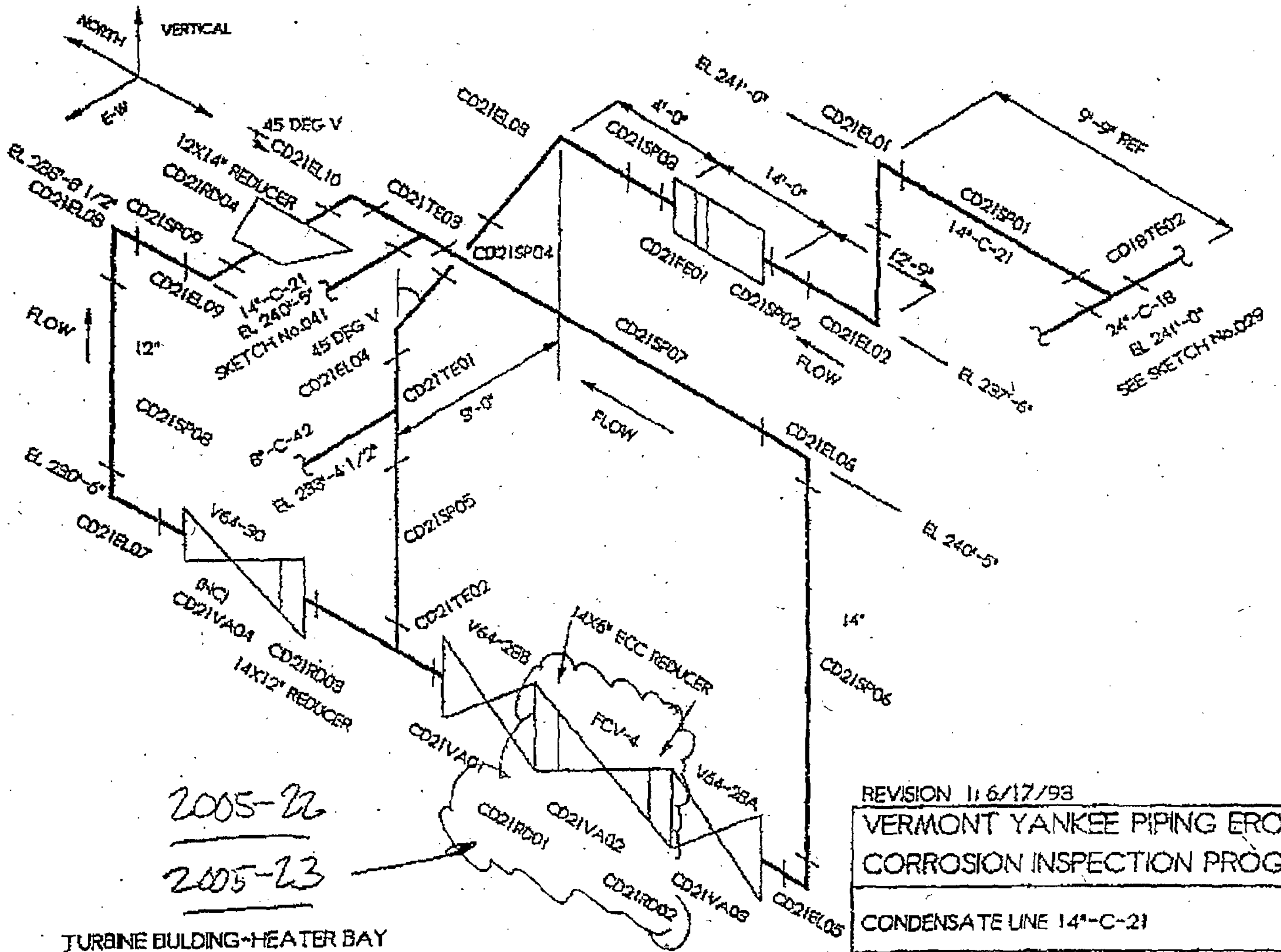
CONDENSATE LINE 20"-C-31

COMPONENT LOCATION SKETCH No. 038

TURBINE BUILDING-FEEDWATER PUMP ROOM
REFERENCES: G191157,G191186,G191187,5920-FS-116

12 of 18

NEC037130



2005-22

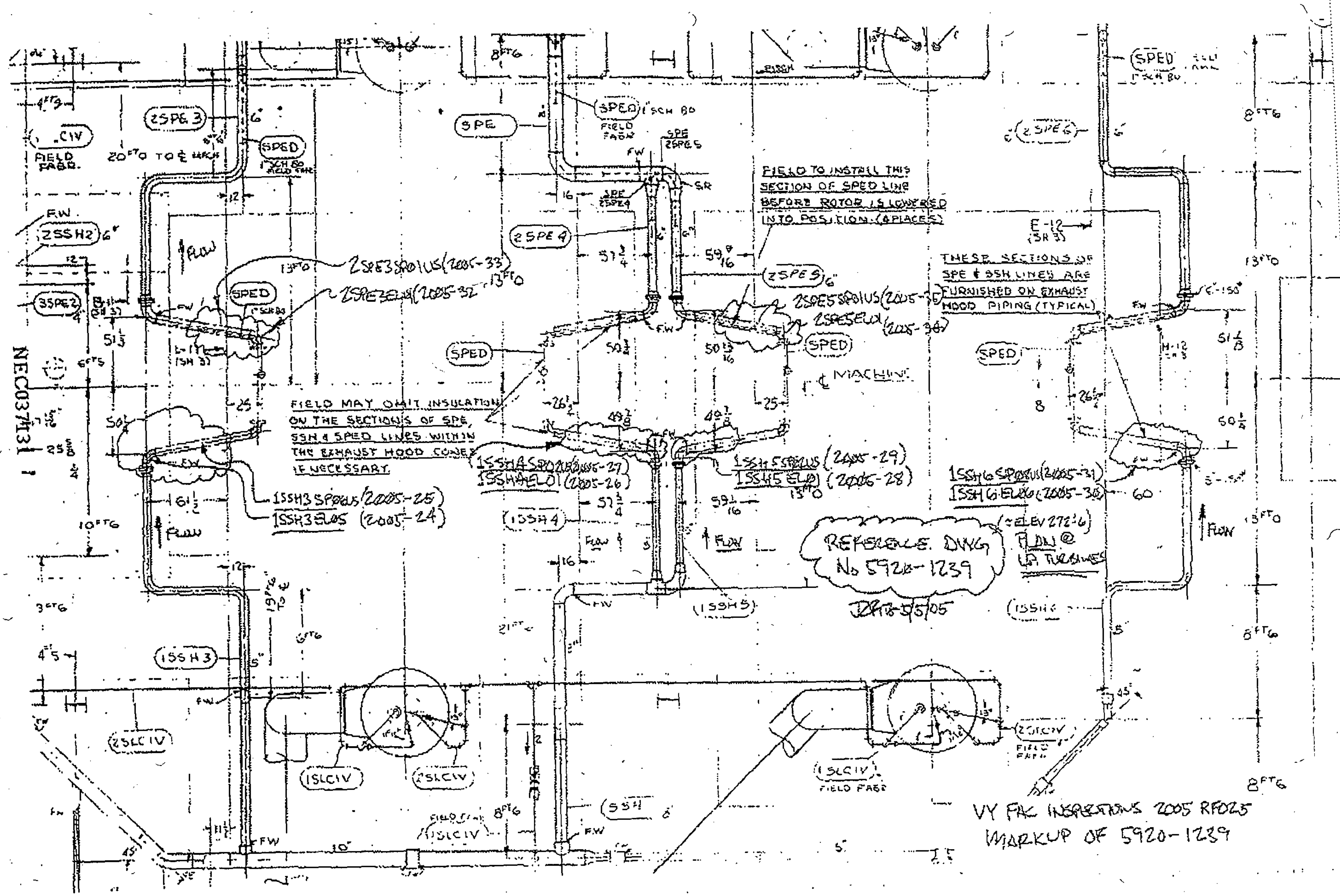
2005-23

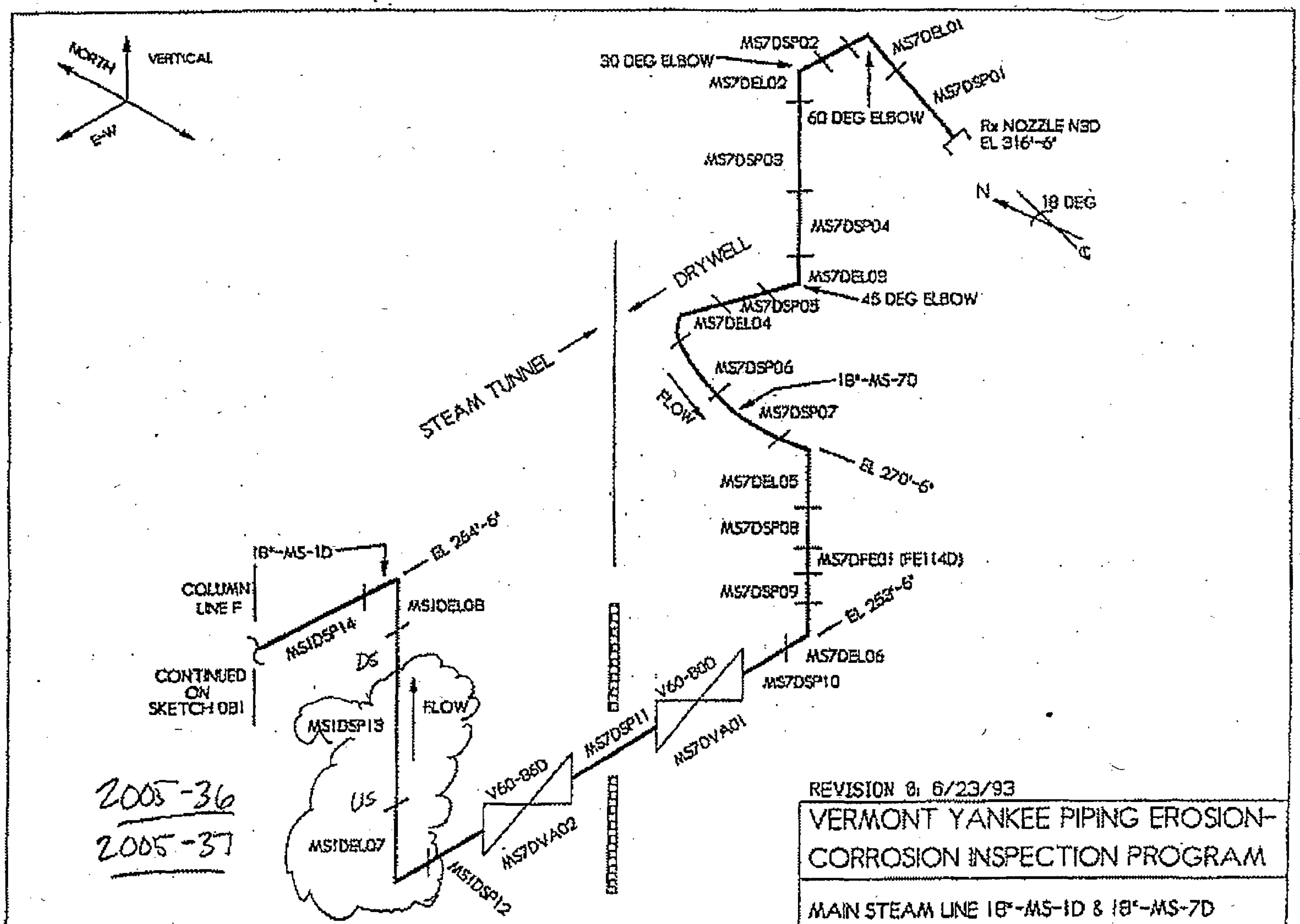
TURBINE BULDING-HEATER BAY
REFERENCES: G191158,G191188,G191189,5920-FS-135

REVISION 1: 6/17/93

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM
CONDENSATE LINE 14"-C-21
COMPONENT LOCATION SKETCH No.040

13 of 16


FIELD TO INSTALL THIS SECTION OF SPED LINE BEFORE ROTOR IS LOWERED INTO POSITION (4 PLACES)
THESE SECTIONS OF SPE & SSH LINES ARE FURNISHED ON EXHAUST HOOD PIPING (TYPICAL)
FIELD MAY OMIT INSULATION ON THE SECTIONS OF SPE, SSH & SPED LINES WITHIN THE EXHAUST HOOD CONES IF NECESSARY
2SPE3SP01US(2005-33)
2SPE3EL01(2005-32)
2SPE5SP01US(2005-35)
2SPE5EL01(2005-34)
1SSH4SP02US(2005-27)
1SSH4EL01(2005-26)
1SSH5SP02US(2005-29)
1SSH5EL01(2005-28)
1SSH6SP02US(2005-31)
1SSH6EL06(2005-30)
1SSH3SP02US(2005-25)
1SSH3EL05(2005-24)
REFERENCE DWG No 5920-1239
(≈ELEV 272'-6) PLAN @ LP TURBINES
JDR 5/5/05
VY FAC INSPECTIONS 2005 RF025
MARKUP OF 5920-1239
NEC037131
C MACHINE
FLOW



2005-36

2005-37

Pg 15 of 18

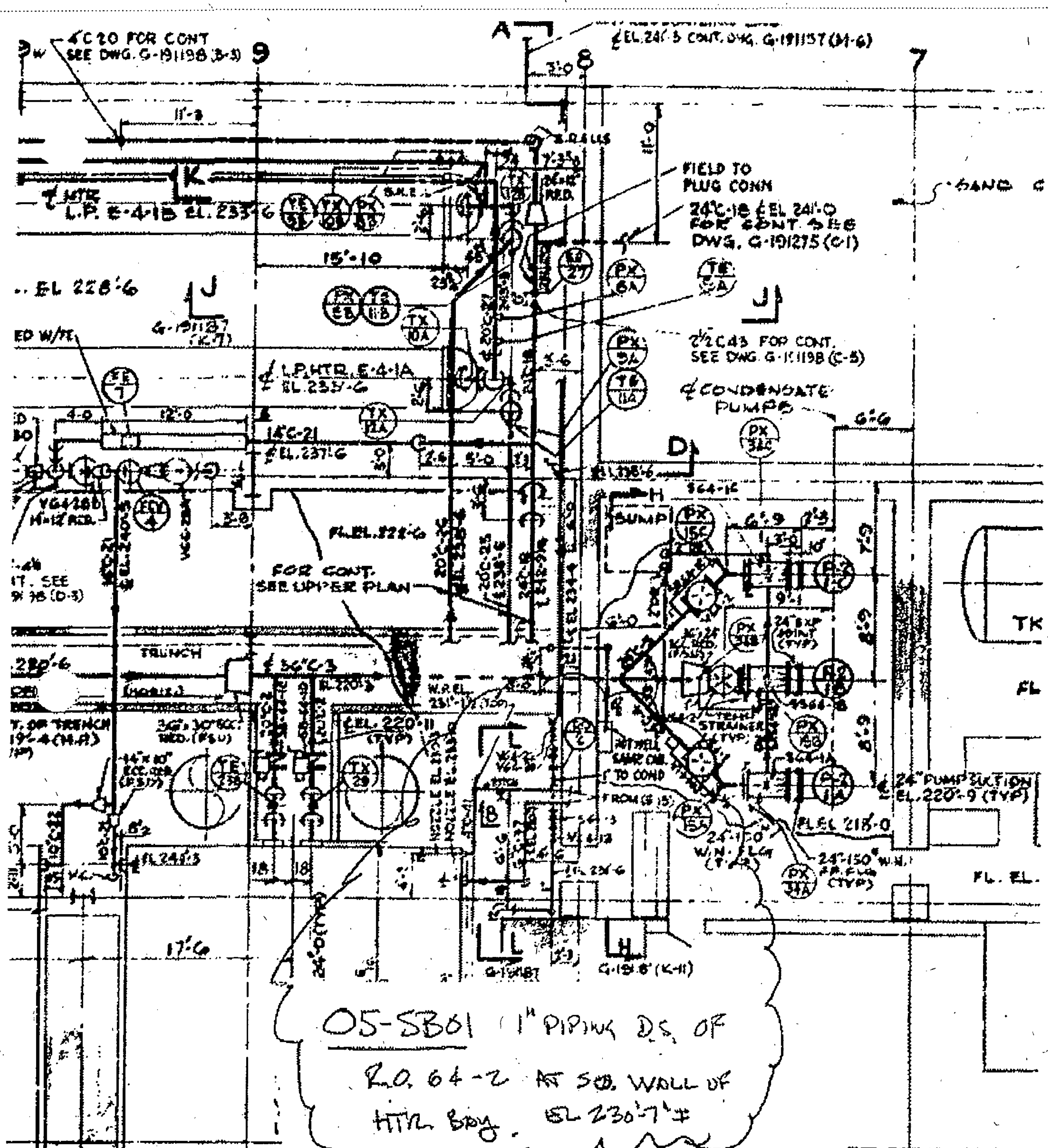
DRYWELL & STEAM TUNNEL
REFERENCES: G191167,G191182,5920-FS-13

REVISION 8: 6/23/93

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

MAIN STEAM LINE 18"-MS-1D & 18"-MS-7D

COMPONENT LOCATION SKETCH No.080



REF. DWG G191186

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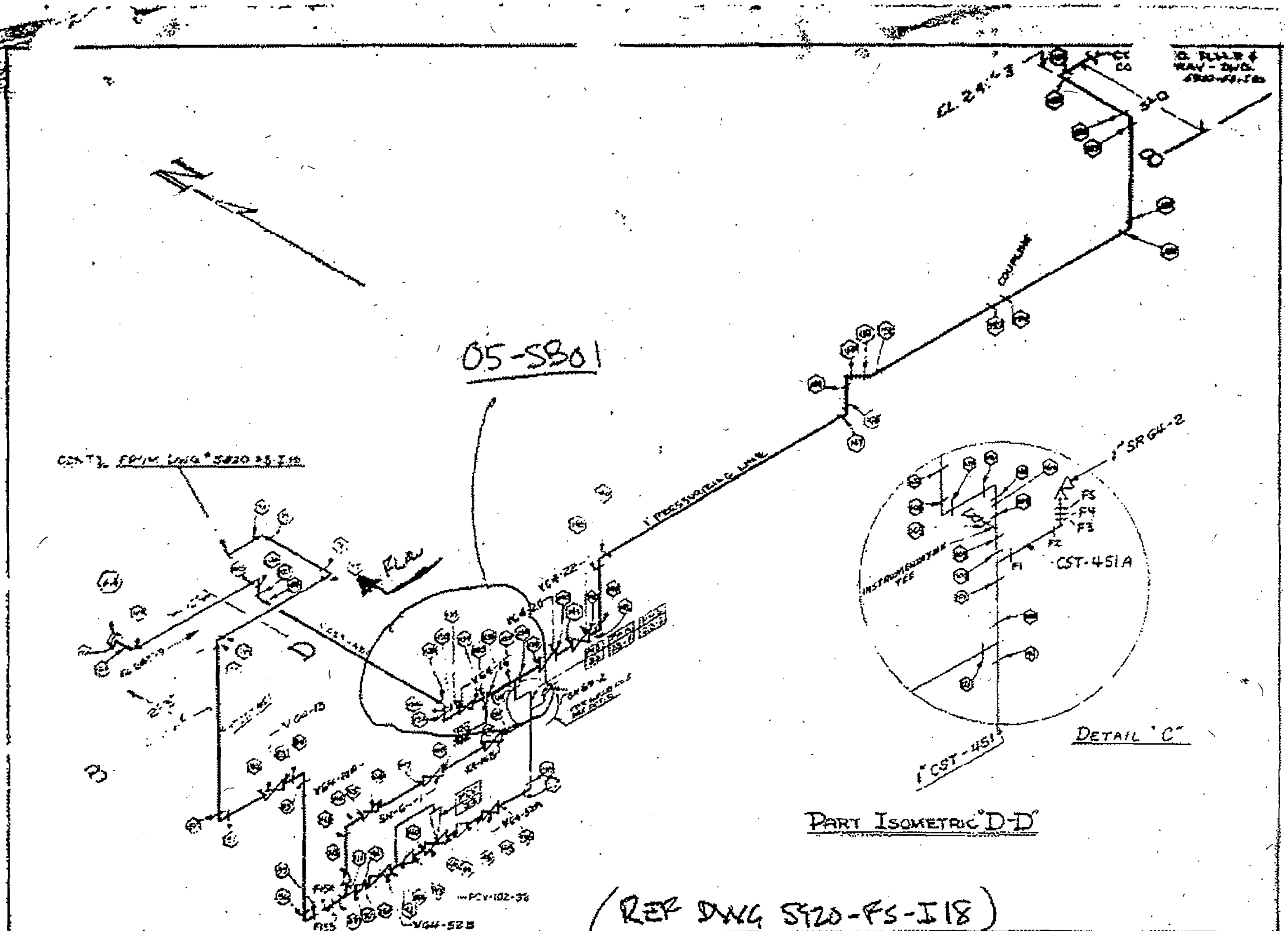
NEC037133

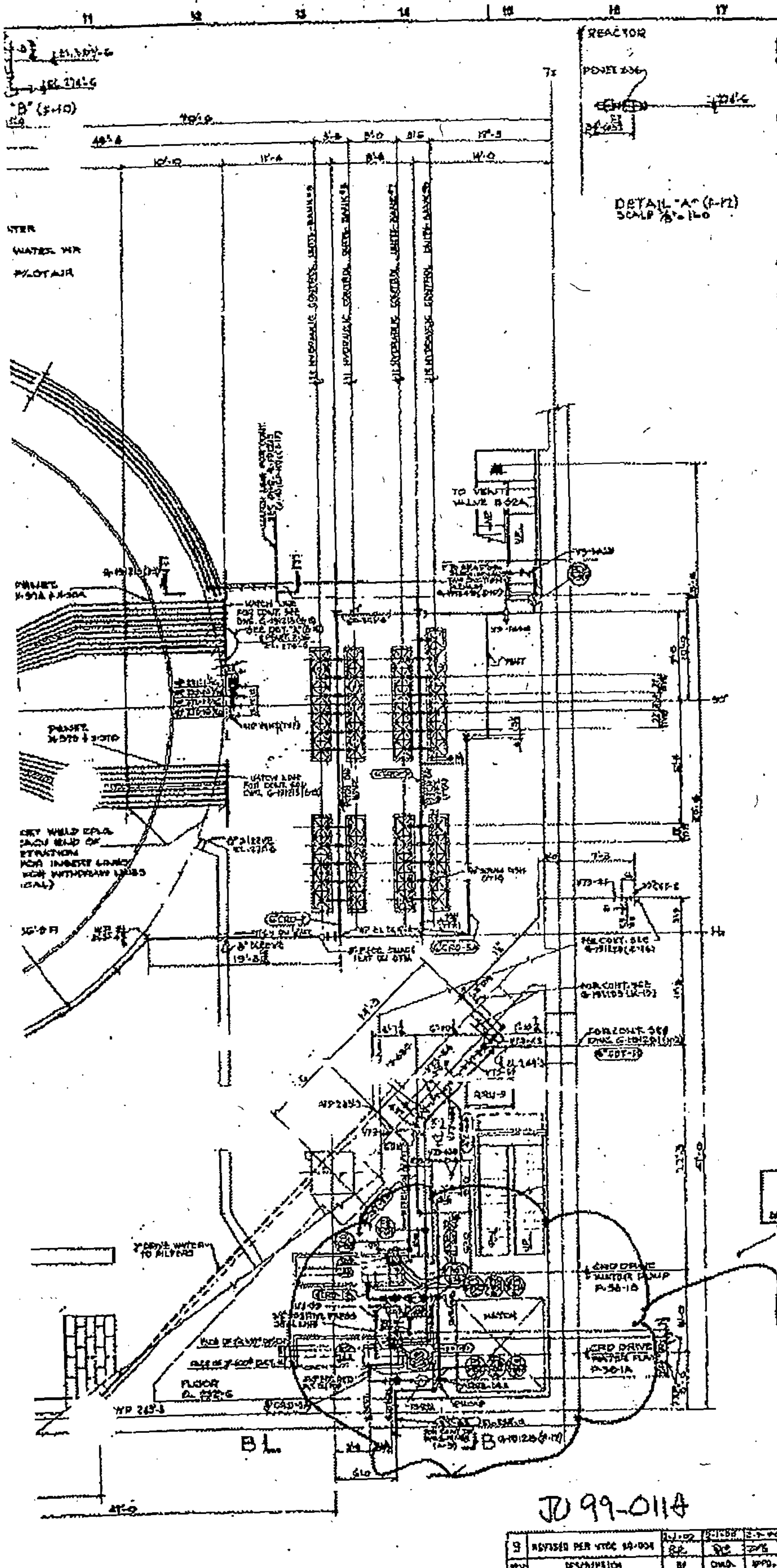
NEC037134



(REF DWG 5920-FS-I18)

	WELL NO.				
[illegible]	CST-451 - F16	121	CST-452-F1[illegible]	154	CST-450-F33
29	F17	122	CST-452 F1	155	F34
[illegible]	F18	123	F2	156	F35
[illegible]	F19	124	F3	157	F36
32	F20	125	F4	[illegible]	F37
33	F21	[illegible]	F5	153	[illegible]

PG 17 OF 18



NOTES:

1. CONTROL ROD DRIVE (CRD) HYDRAULIC SYSTEM SHALL MEET ALL REQUIREMENTS OF CRD HYDRAULIC SYSTEM INSTALLATION SPEC NO [illegible]
2. PIPE BENDS SHALL HAVE A MINIMUM BEND RADIUS OF 5 PIPE DIAMETERS
3. THE HIGH POINT FOR THE INSERT AND WITHDRAW LINES SHALL BE AT THE VENT VALVES NOS (3-180 & 3-182). THE INSERT AND WITHDRAW LINES SHALL PITCH DOWN A MINIMUM OF 1/8"/FT. IN EACH DIRECTION FROM THE POINT WHERE THE VENT PIPING CONNECTS TO THE INSERT AND WITHDRAW LINES. SEE DWG. G-191214.
4. ALL INSERT LINES SHALL BE 1" NOM. PIPE SIZE UNLESS OTHERWISE NOTED.
5. ALL WITHDRAW LINES SHALL BE 3/4" NOM. PIPE SIZE UNLESS OTHERWISE NOTED.
6. DRIP PAN TO BE INSTALLED IMMEDIATELY BELOW PLATFORM IN THE VENT VALVE VENT AREA W/REMOVABLE GRATING ABOVE DRIP PAN. DRAIN SHALL BE PERMANENTLY CONNECTED TO EQUIP. DRAIN.
7. TO IDENTIFY HYDRAULIC CONTROL UNITS AND CONTROL ROD DRIVES THE EVEN NUMBER IS SHOWN FIRST EX. 22-15

PIPING AS SHOWN IS CONCEPTUAL ONLY, EXCEPT FOR PIPING AT CONTROL ROD WATER PUMPS, AND IS SUPERSEDED BY REACTOR CONTROLS INC DRAWING VY-002 SHEET 1 AND 2 EBASCO F.R. 5920-5186 & 5920-5790 R.O.# VYNP-10

REFERENCE DWGS.

LIST OF DRAWINGS	A-191193
GENERAL ARRGT.-REACTOR BUILDING PLANS-SH. 1	G-191148
FLOW DIAGRAM-CRD HYDRAULIC SYSTEM	G-191170
CONTROL ROD DRIVE-HYD. SYS. PIPING-PLANS SH. 2	G-191213
CONTROL ROD DRIVE-HYD. SYS. PIPING-SECTIONS	G-191214
CONTROL ROD DRIVE-HYD. SYS. PIPING-SECTS & DETS.	G-191215
HYDRAULIC CONTROL UNIT	5920-958
DRIVE WATER PUMP	5920-701
DRYWELL CONTROL ROD HOUSING	5920-494
REACTOR BOTTOM HEAD PENETRATIONS	5920-389
REACTOR NOZZ. NO'S	5920-[illegible]

AS BUILT
DATE 9-12-12 APPROVED [signature]
THIS PART ONLY

05-5802
05-5803
05-5804
05-5805

VERMONT YANKEE NUCLEAR POWER CORPORATION
VERMONT YANKEE NUCLEAR POWER STATION
VERNON, VERMONT
REACTOR CONTROL ROD DRIVE HYDRAULIC SYSTEM PIPING - PLAN - SH-1
EBASCO SERVICES INCORPORATED NEW YORK
SCALE 3/8" = 1'-0"
DATE [illegible]
G-191212

9	REVISED PER VYDC 89-004	[illegible]	[illegible]	[illegible]
REV	DESCRIPTION	BY	CHKD.	APPD.

JU 99-0114

NEC037135

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TAB 4

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VERMONT YANKEE
SCOPE MANAGEMENT REVIEW FORM

Date: 11/1/05

Tracking Number: ____
(Assigned by Work Scope Control Coordinator)

Work Order Number: 04-004983-000

Reference Document CR-VTY-04-2925 CA3
(CR, TA, DC, LO, etc)

Initiator: JAMES FITZPATRICK

Approved By: [signature] Dept. Mgr.

Location of Work to be Performed: TURBINE DECK

ADDITION ☐ DELETION ☒ CHANGE ☐

Description

PERFORM UT INSPECTIONS OF STEAM SEAL HEADER PIPING UNDER FAC PROGRAM. INSPECTIONS 2005-24 THROUGH 2005-35

Justification for Request

INTERFERES WITH CRITICAL PATH WORK PLANNED ON L.P. TURBINES SEE ATTACHED MEMOS FOR FAC PROGRAM AND DEFERRAL OF RESTORATION OF TM 2003-031.

Review Process

Additional Cost: ____
Duration and Scheduling Impact: ____
Assigned Dept./Man-Hours to Complete: ____
Source of Manpower/Other Scope Impacted: ____
Dose, Chemistry, Safety Implication: ____
Engineering Impact - Man-Hours/Engineering Dept. ____
Optional Ways to Address: ____

Approval Process

Please provide a brief justification

Scope Review Committee Recommendation/Planning Priority: Approve Delete

Priority "C" WO Responsible Dept Approval ____

General Manager, Plant Operations: [signature] Approve/Disapprove Date: 11-1-05

EMPAC Change Made for Event Code & Priority ____ / ____
SCC Date

Log Updated: ____
Copies to Work Control, Outage Scheduling [initials]

NEC037136

Pg 2 of 6

Prepared By: James Fitzpatrick
Date: 11/1/05

RFO 25 FAC Program inspections location nos. 2005-25 through 2005-35

References:

Work Order 04-004983-000, FAC Inspections
Work Order 04-004983-010, Surface Preparation on SSH piping
TM 04-031
Work Order 04-004884-006
ER-05-0190
CR-VTY-04-2985 CA3

Background:

CR-VTY-2004-02925 documents a steam/water leak on the turbine steam seal piping, line 1SSH4 to the No.4 packing. TM 2004-031 installed a temporary leak enclosure on this line. Inspections on Turbine Steam Seal Piping were included in the scope of the FAC program for RFO 25 per CA3 of CR-VTY-2004-02925. The purpose of these inspections is to determine the extent of condition on the remaining steam seal piping.

Work Scope

These inspections require access to the SSH & SPE piping on elevation 272 of the Turbine Building. The piping is located under the LP turbine appearance lagging deck plates and requires removal of section of the plates to access the piping for surface preparation and inspection. It was intended that these inspections be performed along with restoration of Temp Mod 2004-031 (W.O. 2004-4884-006).

Discussion

Restoration of TM 2004-031 was removed from the outage scope on 10/24/05 due to interference with critical path work planned on the LP turbines. A detailed rationale for delaying restoration of the TM from RFO25 was developed by George Benedict on 9/98/05 and is attached here. The same reasoning and technical basis applies to these inspections.

In addition these inspections are not programmatically required under PP 7028 (Piping FAC Inspection Program). The inspections were added to the RFO 25 scope to determine the condition of the piping at parallel and similar locations on the Steam Seal piping as the 2004 through wall leak.

The system is a low pressure system with piping located in the heater bay or under the turbine deck plating. Deferral of these inspections does not pose a significant personal safety hazard as exposure to these lines during operation is minimal. The possibility of a leak at another location on the Steam Seal piping still exists. However, the low operating pressures and the results of UT measurements made on the 1SSH4 line at the location of the existing leak indicate that any failure would be a pinhole type leak vs. a catastrophic failure of the pipe.

Entergy

Prepared By: G. Benedict
Date: 9/28/05

Pg 3 of 6

Replacement of N4 Steam Supply Piping

References:

Work Order 04-4884-06
TM 2004-031
ER 05-0190

History:

The steam seal supply line to TB-1-1A, N4 packing developed a leak from what appears to be the result of pipe erosion on one of the pipe radiuses. Team Inc. was contacted to develop on-line repair options and determined that the most appropriate long term repair would be to install a pre-fabricated clamping device. The clamp was fabricated as recommended and successfully installed per the above referenced Temporary Modification (TM 2004-031).

Work Scope:

The permanent repair for the N4 steam seal supply line is currently scheduled to be implemented during RFO 25. The pipe clamp and the degraded section of pipe will be removed and new piping will be field fit and installed. To facilitate this work, it will be necessary to remove sections of the LP turbine appearance lagging deck plates to gain access to the piping. Use of the overhead crane will also be required to remove/install piping and deck plates.

LP Turbine and Steam Seal Pipe Repair Interaction:

During RFO 25 a significant amount of work will be performed on the LP turbines which are located in the immediate area of the degraded N4 steam seal supply line. The LP turbines will be completely dismantled to facilitate the installation of the new 8th stage diaphragms and to perform the required ten year inspection. The location of the degraded steam seal line is directly between both LP turbines and implementing the LP inspection in conjunction with the steam seal line repair will create personnel safety hazards, potential equipment damage, and logistical complications.

Entergy

Prepared By: G. Benedict
Date: 9/28/05

Pg 4 of 6

The following represents the specific issues that will be present during the implementation of the N4 steam seal line replacement and the LP turbine inspection:

Personnel Safety:

- Fall and drop hazards will be created by both work crews in proximity to both work areas. Open holes will exist on the turbine deck appearance lagging deck plates and in the area between the LP inner casings and exhaust hoods. Although, personnel protection barriers and equipment will be utilized to mitigate fall and drop hazards, personnel awareness, focus, and goal will be on each individuals own task. The drop and fall hazards will be continually changing as each work activity progresses and although personnel are required to communicate changes to safety hazards these types of changes will be extremely difficult to manage due to the pace of the LP turbine inspection activity.

- The crew working on the steam seal piping will continually be interrupted due to overhead hazards from materials being removed and returned to the LP turbine centerline. Once again due to the pace of the LP turbine inspection and the fact that the steam seal piping replacement crew will be in and out of the work area which is not visible from the turbine floor only increases the potential to inadvertently transfer a load over the piping replacement crew.

Equipment Safety and Quality:

- The removal and installation of the steam seal piping will involve welding and grinding activities. Shielding can and must be installed to prevent inadvertent weld flash, slag, and grinding dust, however, performing these types of activities in the vicinity of open bearing oil sumps, exposed shaft journals, and bearing babbitt surfaces increases the risk for accidental damage.

Schedule and Logistics

- The LP turbine work is the primary critical path activity for the Outage and any delays encountered by the implementation of the N4 steam seal supply line repair will most likely result in an increase in duration. The repair of the steam seal line will require a moderate use of the turbine building crane to remove/install deck plates, piping, and appearance lagging. In addition, crane support will be required to remove damaged pipe...install and fit-up new pipe sections...remove new section to perform non-field welds...and permanent installation. There is zero turbine building crane availability during RFO 25.

- The open hole caused by the removal of deck plating will cause the "A" LP to be logistically separated from the "B" LP on the right side of the centerline which will create a delay in the transfer of tooling and materials between LP "A" and "B".

- Asbestos concern: There is a potential that the steam seal line being repaired contains asbestos insulation. Any asbestos insulation issues could shutdown-work on the turbine deck.

- Maintenance resources: Maintenance crews assigned to the steam seal line repair have 7 shifts available to perform this repair. If there are any delays in performing the repair (e.g. coordination issues or emergent issues during the work), the maintenance crew would be required to leave the steam seal pipe repair and return to the refuel floor.

Technical Basis for Deferral:

Team Inc. was contacted to determine the feasibility of operating the unit for an additional cycle with the Team clamp in place. The response from Team Inc. was very favorable with regard to operating an additional cycle with the clamp in place. According to Jim Savoy (Team Inc. District Manager) many commercial industrial facilities that have utilized clamps similar to the one installed on the N4 steam seal supply line have operated for extended periods much greater than the requested 18 months.

The steam seal supply is approximately 2 – 5 lbs. of pressure with a maximum temperature of 255 degrees F. This is considered very low in comparison to many of the applications that Team Inc. has installed similar long term clamps on. If the clamp is left installed for an additional operating cycle there is a risk that the clamp will leak once the plant is placed back on-line. Although considered a low probability, the risk is due to the thermal cycling of dissimilar materials that are utilized in the clamping and sealing process. If a leak were to occur Team Inc. would re-inject the clamp with sealant which has been successfully performed at other locations.

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VERMONT YANKEE
SCOPE MANAGEMENT REVIEW FORM

Date: 10/23/05

Tracking Number: ______________________
(Assigned by Work Scope Control Coordinator)

Work Order Number: 04-4884-06

Reference Document TM 2004-031
(ER, MM, TM, 0028, etc.)

Initiator: Lee Kitchen

Approved By: ______________________
Dept. Mgr.

Location of Work to be Performed: Turb Deck

ADDITION ☐ DELETION ☑ CHANGE ☐

Description

Replacement of steam seal supply piping. There is a temp leak repair in place.

Justification for Request

Interferes with critical path work planned on the LP turbines. See attached memo that documents the problems that would delay the critical path on the turbine deck.

Review Process

Additional Cost: ______________________
Duration and Scheduling Impact: ______________________
Assigned Dept./Man-Hours to Complete: ______________________
Source of Manpower/Other Scope Impacted: ______________________
Dose, Chemistry, Safety Implication: ______________________
Engineering Impact - Man-Hours/Engineering Dept. ______________________
Optional Ways to Address: ______________________

Approval Process

Please provide a brief justification

Scope Review Committee Recommendation/Planning Priority: ______________________

Priority "C" WO Responsible Dept Approval ______________________

Plant Manager: [signature] Approve Disapprove Date: 10-24-05

EMPAC Change Made for Event Code & Priority ______________ / ______________
SCC Date

Log Updated: ______________

Copies to Work Control, Outage Scheduling, ________; ________; ________

JCM7
TAB 5

RFO-25 Piping FAC Inspections
Outage Scope Challenge Meeting 5/4/05

Short or cryptic summary of what the project involves and why we need to complete the project in RFO 25 (e.g. regulatory requirement, risk to generation, program requirement, appropriate management of the asset.)

In response to USNRC Generic letter 89-08, inspections of piping components susceptible to damage from Flow Accelerated Corrosion (FAC) are performed each refueling outage. The planning, inspection, and evaluation activities are currently defined in program procedure PP 7028, "Piping Flow Accelerated Corrosion Inspection Program". Before the start of RFO25, VY will transition to a new Entergy procedure "Flow Accelerated Corrosion Program", ENN-DC-315.

Description of the scope of the project, what it encompasses, options that have been considered (identify minimal required vs. discretionary – could be deferred scope.) Other outage scope that interfaces with or can be included in this project; Impacts on others.

The scope of the inspections for each refueling outage is based on previous inspection results, predictive modeling, industry and plant operating experience, postulated power uprate effects, and engineering judgment. The scope for the Fall 2005 RFO is defined in Design Engineering-M/S Memo VYM 2004/007, Revision 1. The 2005 RFO Scope includes:

External Ultrasonic Thickness (UT) Inspection of 37 large bore components at 16 locations. Includes:

- 5 components recommended for repeat inspections based on prior UT data
- 2 components for CHECWORKS model calibration
- 6 components based on Operating Experience (Mihama Event)
- 6 components downstream of leaking N.C. valves (identified from TPM)
- 4 components based on increased EPU flows
- 2 components D.S of FCV -104-4 (suspected cavitation)
- 12 components based on current through wall leak in SSH at LP turbines

External Ultrasonic Thickness (UT) Inspection of 5 sections of small bore piping based on industry experience. Includes 4 sections of piping downstream of restriction orifices at the CRD pumps.

Internal Visual Inspection of two 36 inch CAR lines to assess changes in flows from HP turbine modifications installed in RFO 24. Internal Visual inspection of the only remaining carbon steel 30 inch diameter line 30"-B.

Pre-outage scope and long lead time parts/contracts that have been identified.

None

RFO-25 Piping FAC Inspections
Outage Scope Challenge Meeting 5/4/05

Initiatives, creative opportunities, unique problems associated with the project.

None

The inspection process used is the industry standard. Removal of insulation and surface preparation are required for the UT equipment. Remote methods which do not require insulation removal are still in the development stage, and do not currently have the accuracy required to trend low wear rates (EPRI CHUG). Phosphor Plate Radiography which is currently being adopted to screen small bore components without insulation removal is primarily applicable to PWR plants. Limited use on BWRs.

Design Engineering – M/S has minimized the number of inspections performed each RFO. VY has traditionally trended well below industry average number of components inspected each RFO. This is primarily due the original design of the plant and replacements with Chrome-Moly piping. Recent trends in numbers of components inspected at other plants show reduced numbers of inspections based on piping replacements.

Identify additional organizational support required, and specifically, management support necessary.

Inspections will be performed by the ISI personnel. Scheduling and staffing will be coordinated with other ISI activities. Inspections are performed using approved NDE procedures. Training on inspection procedures is performed under the ISI program. Grid marking per new ENN Standard ENN-EP-S-005

Primary DE-M/S interface is the ISI Level III and/or ISI Program Engineer for coordination in review and approval of inspection data. Interface with craft & other plant groups is normally through established links in the ISI program. Unusual situations which require additional support will be raised to management level as required.

Two DE-M/S engineers (J.Fitzpatrick & T.O'Connor) currently trained in evaluation procedures and have prior VY FAC Program Experience. Other DE-M/S engineers with pipe stress experience can be trained on short notice. The number of inspections is slightly higher than the last two outages. Coverage will be provided 7 days a week (or as required) to evaluate UT data.

The FAC Program Coordinator (J.Fitzpatrick) is responsible to insure that inspections are performed and the data is evaluated in accordance with the program requirements. Activities will be coordinated with the ISI coordinator (Dave King). Any problems that arise that can not be handled at the engineer level, will be elevated per outage management guidelines (30 minute rule, etc.).

RFO-25 Piping FAC Inspections
Outage Scope Challenge Meeting 5/4/05

Identify any preparation issues necessary to meet upcoming outage milestones.

- Coordination with L.P Turbine work for inspection of SSH components (physical space)
- Coordination with L/P Turbine/Condenser work for ventilation path (opening) for the 30" B Cross Around Line and for a window to perform inspections (noise issue).
- ER for Design Engineering – Fluid Systems to develop a (paper) Design Change to reduce the piping design pressure in the Feedwater Pump Bypass Lines at the condenser. Current design pressure for the piping attached directly to the condenser is 1900 PSI. Local sections of carbon steel piping remain at the condenser. Leaking valves during past operation cycles may have resulted in increased wear in carbon steel section of line.

Identify if all necessary outage and pre-outage WO's for the project/program scope are generated.

Work Orders to for support activities and inspections (04-4983-000 series) W/ M. Griffin @ Program.

Identify if any opportunities to perform any part of this scope could be completed pre-outage?

The only components which are not high temperature and are in an accessible location during plant operation are 4 sections of small bore piping downstream of restriction orifices at the CRD pumps. These may be inspected during operation. However, this is a high noise area.

(uninsulated.)

TAB 6 Pg 1 of 2

Engineering Standard Review & Approval Form

Engineering Standard Change Classification									
New	☒	Revised	☐	Cancel	☐	Editorial	☐	Temporary (TCN)	☐

Engineering Standard Title	Doc. No.	Rev No.	TCN No.
Flow Accelerated Corrosion Component Scanning and Gridding Standard	ENN-EP-S-005	0	N/A

Functional Discipline	Engineering Standard Owner	Engineering Standard Preparer
Engineering Programs	Jeffery Goldstein	Ian Mew

Site Conducting Reviews									
ANO	☐	ECH	☐	GGNS	☐	RBS	☐	WF3	☐
IP	☐	JAF	☐	PNPS	☐	VY	☒	WPO	☐

Review Type	Yes	No	Reviewer Name/Signature	Date
Technical Review (See Note below for Design Change Standards)	☒	☐	James C. Fitzpatrick JCF	9/21/05
Independent Design Verification (See Note below for Design Change Standards)	☐	☒		
10CFR50.59/Process Applicability Review (attach screening and evaluation documents) (See Note below for Design Change Standards)	☒	☐	James C. Fitzpatrick JCF	9/21/05

Note: *Reviews for Design Change Standards are Documented within the applicable ER.*
** An ER Number is required for Design Change Standards, only.*

ER Number:

Cross Discipline Reviews (Department Name)	Yes ☐	No ☒	Reviewer Name / Signature	Date
N/A				
Site Engineering Standard Champion			Scott D. Goodwin S. Goodwin	9-22-05

Editorial Change / TCN Approval

Name:	Signature:	Date:

Comments Section			
Comments Made Below	☒	Comments Attached	☐
TCN Change Below	☐	TCN Change Attached	☐
TCN Effective/Expiration Date			

Comments/TCN Change:

This standard replaces VY specific "Component Gridding Guidelines" previously contained in Appendix A of VY NDE procedure NE-8053. NE-8053 has been superseded by ENN-NDE-9.05

All VY comments were resolved during development of this standard.

Pg 2 of 2

ENTERGY

ENN
ENGINEERING
STANDARD

ENN-EP-S-005	Rev. 0	Effective Date:	JAF/WPO - 9/1/04 PII - 6/1/05 IPEC-10/1/04

Flow Accelerated Corrosion Component Scanning and Gridding Standard

Applicable Site(s):

IP1 ☐ IP2 ☒ IP3 ☒ JAF ☒ PNPS ☒ VY ☐

Safety Related: ____ Yes

__x__ No

Prepared by: Ian Mew Ian Mew 8/11/04
Print Name/Signature/Date

Approved by: Jeffrey Goldstein Jeff Goldstein Date: 8-11-04
Engineering Guide Owner

TAB 7
PAGE 1 OF 2

Engineering Standard Review & Approval Form

Engineering Standard Change Classification									
New	☒	Revised	☐	Cancel	☐	Editorial	☐	Temporary (TCN)	☐

Engineering Standard Title	Doc. No.	Rev No.	TCN No.
Pipe Wall Thinning Structural Evaluation	ENN-~~CE~~ CS-S-00~~7~~8 SCG 9/22/05	0	

Functional Discipline	Engineering Standard Owner	Engineering Standard Preparer
Civil/Structural	R. Penny	H. Y. Chang

Site Conducting Reviews									
ANO	☐	ECH	☐	GGNS	☐	RBS	☐	WF3	☐
IP	☒	JAF	☒	PNPS	☒	VY	☒	WPO	☒

Review Type	Yes	No	Reviewer Name/Signature	Date
Technical Review (See Note below for Design Change Standards)	☒	☐	James C. Fitzpatrick	9/21/05
Independent Design Verification (See Note below for Design Change Standards)	☒	☐	James C. Fitzpatrick	9/21/05
10CFR50.59/Process Applicability Review (attach screening and evaluation documents) (See Note below for Design Change Standards)	☒	☐	James C. Fitzpatrick	9/21/05

Note: *Reviews for Design Change Standards are Documented within the applicable ER.*
* *An ER Number is required for Design Change Standards, only.*

ER Number *

Cross Discipline Reviews (Department Name)	☐	☒	Reviewer Name / Signature	Date
N/A				
Site Engineering Standard Champion			Scott D. Goodwin	9.22.05

Editorial Change / TCN Approval

Name:	Signature:	Date:

Comments Section			
Comments Made Below	☒	Comments Attached	☐
TCN Change Below	☐	TCN Change Attached	☐
TCN Effective/Expiration Date			

Comments/TCN Change:

All VY comments resolved during development of this standard.

NEC037147

Fitzpatrick, Jim

Pg 2 of 2

From: Fitzpatrick, Jim
Sent: Tuesday, September 27, 2005 11:45 AM
To: VTY_Engineering-Mechanical Structural; VTY_EFIN_DL
Subject: FW: Communication of Approved Engineering Standard

FYI

This is a new fleet standard for evaluation of thinned wall piping components which will replace ENN-DC-133. ENN-DC-133 will be superseded.
VY Department Procedure DP 0072, "Structural Evaluation of Thinned Wall Piping Components will be revised or superseded as required when ENN-DC-315 is adopted.

Use:
Entry Conditions for this Standard will be in ENN -DC-315 "Flow Accelerated Corrosion Program" and ENN-DC-185 "Through wall leaks in ASME Section XI Class 3 Moderate Energy Piping Systems". WPO has the responsibility to revise the references to ENN-DC-133 in these procedures.

Qualifications/Training :
At present there is no ENN QUAL CARD for use of this Engineering Standard. Calculations performed using standard are documented per ENN-DC-126. Based on the scope of this standard, only Design Engineering – Civil/ Structural personnel and the Mechanical types in EFIN with previous pipe stress experience have the charter and background to apply this standard.

Summary of Changes from ENN-DC-133 as applicable to VY:

- More formalized ties to ENN-DC-315, Wear rate determination for FAC program inspections is the responsibility of the FAC Program Engineer
- Calculation of component Wear, Wear Rate and Predicted Thickness is consistent the same as DP0072. The only change from DP0072 is a reduction on the Safety Factor (SF) from 1.2 to 1.1.
- The methods used to calculate the code required thickness for pressure and moment loads are consistent with DP0072, but presented in a different format.
- No significant changes to application of ASME Code Case N-513 for though wall leaks
- Added attachment for guidance in calculation of component wear rates.
- Excel spreadsheet templates are available to facilitate calculations.

From: Ettlinger, Alan
Sent: Monday, September 26, 2005 9:33 AM
To: Casella, Richard; Fitzpatrick, Jim; Lo, Kai; Pace, Raymond
Cc: Unsal, Ahmet
Subject: Communication of Approved Engineering Standard

In accordance with EN-DC-146, as the Site Procedure Champion (SPC) at your site, please inform and communicate to applicable site personnel, the issuance of the following fleet NMM Engineering Standard.

ENN-CS-S-008, revision 0 Pipe Wall Thinning Structural Evaluation

This standard supersedes ENN-DC-133. The standard can be accessed in IDEAS on the Citrix server.

The standard becomes effective, and will be posted on September 28, 2005.

If you have any questions, please give me a call.

ATTACHMENT C

NEC-UW_03

REDACTED

EVALUATION OF VERMONT YANKEE NUCLEAR POWER STATION LICENSE EXTENSION: PROPOSED AGING MANAGEMENT PROGRAM FOR FLOW ACCELERATED CORROSION

Ulrich Witte
Northern Lights Engineering
71 Edgewood Way
Westville, CT 06515

April 25, 2008

TABLE OF CONTENTS

I. Introduction

I submit the following comments in support of the New England Coalition, Inc.'s ("NEC") Contention 4. My comments concern the Applicant's aging management program, specifically addressing the fidelity of the Flow-Accelerated Corrosion ("FAC") Program (NEC Contention 4).

NEC asserts that the application for License Renewal submitted by Entergy for Vermont Yankee does not include an adequate plan to monitor and manage aging of plant equipment due to flow-accelerated corrosion ("FAC") during extended plant operation. The Applicant has represented that its FAC management program during the period of extended operation will be the same as its program under the current operating license, and consistent with industry guidance, including EPRI NSAC 202L R.3. The use of the CHECWORKS model is a central element in the Program implementation.

In the Applicant's motion for summary disposition, the Applicant proffered a response that credits the its current program for FAC management at the facility, and simply extends the current program for the renewal period, making the following statement: "furthermore, the FAC program that will be implemented by Entergy is the same program being carried out today, which has not been otherwise challenged by NEC, will meet all regulatory guidance." Ref. Entergy Motion for Summary Disposition on New England Coalition's Contention 4 (Flow Accelerated Corrosion), June 5, 2007, at 3. Italics added.

The Applicant has asserted that it is in full compliance with its current licensing basis regarding its FAC program. The Applicant asserts that the plans for monitoring flow accelerated corrosion, including the FAC Program goal of preclusion includes appropriate procedures or administrative controls to assure that the structural steel integrity of all steel lines containing high-energy fluids is maintained. *Id* at 6. The applicant is argues that since the VY FAC program is based on EPRI guidelines and has been in effect since 1990, one could therefore conclude the applicant has established methodology so as to preclude of negative design margin or forestall an actual pipe rupture, and Entergy infers that it is technically adequate and is compliant with its licensing basis requirements.

I draw a different conclusion. Based on the *implemented* program presently in place, and the historical inadequacies necessary for effective implementation (including evolution) of the FAC program, the oversights are substantial in program scope, application of modeling software, and finally necessary revisions to the program not implemented as was promised to support the power up-rate. I am not alone in this conclusion. Program weaknesses and failures have been identified by others and form the basis of condition reports, the categorization as *unsatisfactory* in a Quality Assurance Audit dated November 11, 2004[1], and noted as "yellow" in a cornerstone roll-up report circa 2006[2]. In addition, the NRC Project Manager made a recent inquiry into indications of an out-of-date program.[3] On Monday, April 21, 2008, I spoke by phone with NRC resident inspector Beth Sienel, and she confirmed that, even now, Entergy has not completed verification of the upgrade of the CHECWORKS model to EPU design conditions. This concern regarding deficiencies in implementation of the program brings into question the results of FAC inspection during RFO 25 and RFO 26, in which power up-rate design data apparently is as yet not incorporated.

[1] Exhibit NEC-UW_9, Audit No.: QA-8-2004-VY-1, "Engineering Programs", page 2, NEC038514

[2] Exhibit NEC-UW_7, Cornerstone Rollup, Program: Flow Accelerated Corrosion, Quarter: 3rd, dated 10/03/2006, page NEC03824, Open Action Items, (includes All CR-CAs, ER post action items and LO-CAs, is shown as "yellow", however, 6 LO-CAs are shown as open. By definition, "Red" includes 2 or more CR-CAs and /or E/R post action items (excluding LOs action items) greater than one year.

[3] Exhibit NEC-UW_14.

These program implementation delays are substantive, and based upon the information provided to NEC appear to remain unresolved. These deficient conditions raise questions as to the fidelity of the entire license renewal application, Entergy's commitments for license renewal, management oversight, and the efficacy of the regulatory-required Corrective Action Program.

If it is true that power up-rate parameters such as flow velocity were not incorporated into the FAC program model, these deficiencies appear to be substantive and without question warrant condition reports under the Entergy Corrective Action Program, in particular given that they appear to violate regulatory commitments regarding the Flow Accelerated Corrosion Program.

10 CFR Part 50 Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," provides that a condition that is deficient is *required* to be identified, investigated, and remediated expeditiously.[4] Promises to correct the deficient program at some point in the future are not sufficient, unless all reasonable alternative methods for remediation are exhausted and the condition is shown to be safe in the interim. Lack of oversight and a *single missed inspection point* that remained unnoticed

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[4] 10CFR Part 50, Appendix B, XVI, "Corrective Action," states: "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management."

for years[5] led the Japanese Mihama Plant FAC pipe rupture in 2004, causing five fatalities.[6] As discussed in detail below, Vermont Yankee missed dozens of points.

Identification of discrepancies and timely corrective action are the cornerstones of a well-managed plant. In my experience assisting problematic plants, change usually begins with a cultural shift toward proactive corrective action and away from a reactive mentality of delaying needed corrective actions to programs such as FAC that result in unresolved deficient conditions and unnecessarily narrowed safety margins for longer periods of time than are necessary.

A common metric used by the regulator (for example in ROP reviews) and management is the volume of the backlog of open corrective actions and the number of open corrective actions that date further back than one year, two years or even three or more years, to establish the fidelity of the licensee's compliance with the terms of its operating license and associated commitments. The metric is useful in evaluating Flow Accelerated Corrosion management at Vermont Yankee.

II. Summary Assessment

Based on a detailed review of the record provided to NEC regarding the Flow-Accelerated Corrosion Program, my conclusion is that the FAC program appears to have been in non-compliance with its licensing basis from about 1999 through February 2008. The failure to comply is evidenced by the licensee's own assessments, audits, and condition reports, roll-up of numerous cornerstone reports, and focused self-assessments. Corrective actions from approximately five Condition Reports ("CR") remained open for

[5] Exhibit UW_20, Page 6 of 14 of VY FAC Inspection Program PP7028, 2005 refueling outage. NEC0737109

[6] The Japan Times, September 28, 2004.

as much as four years. The last condition report regarding FAC, CR 2006-2699, was written on August 30, 2006. Although noted in the cornerstone report dated October of 2006[7], the condition report apparently was never provided to NEC. The condition report aggregated approximately six corrective actions to the program that had been ignored and the current status was then open and which is presently unknown to NEC.

In addition, the most recent FAC inspection was performed under superseded procedures and the results therefore are of potentially no programmatic value[8]. Procedure ENN-DC-315, was revised and in effect on March 1, 2006, yet superseded on December 1, 2006 by yet a new program level procedure. Close examination shows that the procedures prepared, approved and implemented by Entergy for implementing the FAC Program were substantially revised, yet were not used in the most recent flow-accelerated corrosion inspections after VY increased operating power by 20 percent in the March, 2006 EPU, nor were they available for RFO 25, the first outage after power up-rate. Required changes, including both a software upgrade and design parameters regarding the substantial plant modification to uprate the plant to 120% power, were not incorporated for either outage, and were in fact still being implemented in February 2008, when Staff inquired on this subject.

[redacted]

[7] Exhibit NEC-UW_07 Cornerstone Rollup, Program: Flow Accelerated Corrosion, Program Infrastructure Cornerstone, Quarter: 3rd, dated 10/03/2006, page NEC03119, "Corrective Action Plan to complete open LO-CA tasks developed 10/02/2006, (CR-2006-02699)—see also footnote 3.

[8] Exhibit NEC-UW_20, VY Piping FAC Inspection Program PP 7028- 2007 Refueling Outage, Inspection Location Worksheets/ Methods and Reasons for Component Selection," April 3, 2006, at 1, NEC017888

[redacted]

[redacted]. The Feedwater System FAC review was run using 1999 Ultrasonic Test ("UT") data, yet the results were not used in the RFO 24 outage.

To be an even marginally predictive modeling tool, the CHECWORKS model should have been kept current for successive outages, including multiple systems changes (as defined by EPRI guidance[10]) that were required to be managed for FAC as far back as 1999. The predictive capability of CHECWORKS was virtually non-existent for the period from 1999 forward. Although Entergy did incorporate the program, which depends heavily on trending of data of multiple outages, they incorporated in one plunge plant design conditions during the 3rd quarter 2006. The scoping document supporting selection of grid points collected essentially all the sins of the past, including, for example, stale predictive inspection data from the out-of-date version of CHECWORKS, and placed heavy reliance on engineering judgment. As provided under the 2005 scoping document[11], the rationale for selection of grid points relied on (1) length of time since the lapsed

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[redacted]

[10] Exhibit NEC-UW_22.

[11] Exhibit NEC-UW_20, PP7028 Piping FAC Inspection Program, FAC Inspection Records for 2005 Refueling Outage, undated, NEC037099. Includes on page NEC037104, Inspection Locations and Reasons for component selection, dated 3/1/05. Note on page 2 of 14 of this report, exclusions of inspection scope were based upon cycle predictions from 1999, and did not appear to include Uprate design changes, nor account for the EPRI model not being current. Many recommendations from 1999 were not to reinspect until 2007—or 9 years. This approach appears to be entirely inconsistent with NSAC 202L. Newer examinations showed an trend of increased frequency of reinspection . See NEC037106. Page 4 of 14 provides for negative margin, or no inspections for Feedwater System. Conclusions called for "assessing the need" for inspections in 2007 outage. See page NEC37107. The condensation system showed one component with negative time to Tmin. The Extraction Steam System indicated three components with negative time to code min wall. Page NEC0737108.

inspections had ceased to examine a particular inspection point, (2) CHECWORKS User Groups, (CHUG) suspects found at other plants, (3) exclusion of components that were intended to be replaced based upon another regime or degraded condition.

Had data from previous FAC inspections routinely been entered into CHECWORKS, the selection of grid points and ranking would have provided a better historical perspective on where to inspect in successive outages, including the most recent outage. With the exception of VY's strength in reactively replacing piping or components with FAC-resistant material during repairs or maintenance, the program itself was not effective as a predictive modeling tool. Simply stated, once something ruptured or was found to be outside its design margin, it was replaced in a reactive management approach. Proactive management of the program to *predict failures* has been inadequate in the FAC Program, as referenced above.

Even the most recent inspection completed for RFO 26 appears to have been structured around procedures that were superseded, scoping requirements to establish a new baseline of pipe geometry and as-found wall thickness were based on stale data, and the upper-tiered governing procedure that was used had not been revised since 2001 and was therefore void.[12]

The current program-level procedure had been in existence since March 2006. Scoping was performed in May of 2006 under the void procedure, and updating of

[12] Exhibit NEC-UW-11, Official Transcript of Proceedings ACRST-3397, Advisory Committee on Reactor Safeguards Subcommittee on Plant License Renewal, June 5, 2007, at page 43. Entergy's Mr. Dreyfuss stated: "...we did increase the number of FAC inspections by 50 percent from what we typically do in outages. We did 63 inspections overall." It is also noted that the average number of points examined by the domestic industry is 82—under a well managed program, without significant changes to the model—such as a power uprate.

CHECWORKS was not done until 3rd quarter 2006.[13] Grid points, scope selection, and small bore piping susceptibility do not appear to have been ranked under NSAC 202L guidance or in an orderly trending of data by CHECWORKS based upon repeated passes with new grid points and new rankings selected. Data input and passes by CHECWORKS were not accomplished on an outage-by-outage basis.[14]

With only 63 points examined in RFO 26[15], the baseline for the power up-rate conditions appears not to have been established. I found it troubling that RFO 26 results were provided to the Advisory Committee on Reactor Safeguards ("ACRS") on June 5, 2007, but apparently were not disclosed to NEC.

VY is the first plant modified to achieve Constant Pressure Power Up-rate to 120% power and only one other plant out of the fleet of 104 was licensed to 120% increase in power in one step. Given the uniqueness of the design of VY's power up-rate, CHECWORKS has little industry benchmarking data, and is of marginal use.

The history of the one other up-rated power plant, Clinton Power Station, suggests the possibility of future problems at Vermont Yankee. The NRC inspected Clinton Power Station, including a review of the FAC program, after its up-rate in January 2003 and found the program to comply with its licensing basis, including NSAC 202L and the use of CHECWORKS. Program inputs were fully incorporated from previous inspection data and heat balance up-rate data. Wear rates were predicted to increase 8% because of up-

[13] Exhibit NEC_UW-10.

[14] Exhibit NEC_UW-20, VY Piping FAC Inspection Program PP 7028- 2007 Refueling outage, Inspection Location Worksheets / Methods and Reasons for Component Selection" at 9, NEC017896

[15] Exhibit NEC-UW-11, Official Transcript of Proceedings ACRST-3397, Advisory Committee on Reactor Safeguards Subcommittee on Plant License Renewal, June 5, 2007, at page 43. Entergy's Mr. Dreyfuss stated: "...we did increase the number of FAC inspections by 50 percent from what we typically do in outages. We did 63 inspections overall." It is also noted that the average number of points examined by the domestic industry is 82—under a well managed program, without significant changes to the model—such as a power uprate.

rated power conditions. Although the increase was a concern to the regulator, the program was found to be adequate. Yet only nine months later, Clinton experienced a FAC rupture[16]. It is relevant that this failure occurred approximately 16 years after Clinton received its operating license in 1987—while apparently complying with its CLB and the EPRI guidance.[17]

Plant Surry, where a rupture due to FAC killed four people, failed after 15 years of operation, and required 190 component replacements due to FAC. The accident led to unpredicted causal events outside the engineering design basis—including discharge of CO_2, seepage of the heavier than air gas into the control room, requiring reactor operators to don Scott air packs and with some operators exhibiting symptoms such as dizziness because of control room habitability[18]. Pleasant Prairie, a fossil plant with similar conditions, endured a catastrophic FAC failure at 13 years, causing two fatalities[19], and a Japanese plant failed without warning, killing five people, simply because of a failure to inspect one component section due to an administrative oversight, repeatedly missed by program owners.[20] The oversight was never noticed during quality control or quality assurance reviews, or spotted by the system engineers responsible for FAC at the plant.

These plants were not specifically using aging management tools, where as others, such as Clinton, did—but each FAC failure occurred well before the plants reached their

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[16] Exhibit NEC_UW-20, at 7, NEC017894

[17] Exhibit NEC_UW-04; Exhibit NEC_UW-O5.

[18] Exhibit NEC-UW_22 U.S. NRC NUREG 0933; Issue 139: thinning of Carbon Steel Piping in LWRs (Rev. 1).

[19] Exhibit NEC_UW-21, Milwaukee Sentinel, March 9, 1995.

[20] Exhibit NEC_UW-20 at 9, NEC017896

engineered end-of-life of 40 years. The event at Mihama occurred due to nothing more than an administrative failure to routinely inspect a known FAC-susceptible component.

I fully concur with NEC's consultant Dr. Joram Hopenfeld that comprehensive benchmarking will be required through the number of years when unmanaged FAC failures typically begin to emerge, such as the operational age of the Surry plant at the time of FAC failure, or the Clinton Plant failure.

III. Licensing basis for management of flow-accelerated corrosion at VY and review of the program implementation

I reviewed the FAC program in four parts: Part A, examining the current licensing basis; Part B, the *implementation* of the licensing basis; Part C, the Licensee's *own record* of problems with implementation; Part D, *my independent observations* based on the record provided to NEC, and the requirements for implementing an effective program under NRC-endorsed guidance, with which the Licensee has stated that it has complied.

A. The current licensing Basis and the proposed licensing basis for the flow accelerated corrosion program:

My review to establish the current licensing basis and the current status of application for license renewal includes the following documents:

1. NUREG 1801 Rev 1, §XI-M17, Flow Accelerated Corrosion

2. [redacted]

21 [redacted]

3. CHECWORKS EPRI procedures provided by the Applicant, including fleet procedure EN-DC-315, Rev. 0, "Flow-Accelerated Corrosion Program" effective December 1, 2006.

4. Commitments made by the licensee including the following:[22]

   i. USNR generic letter 89-08, Erosion corrosion –induced pipe wall thinning;

   ii. Vermont Yankee Letter to USNRC;

   iii. Vermont Yankee letter to the USNRC, Vermont Yankee Response to NRC Bulletin No. 87-01: Thinning of Pipe Walls in Nuclear Power Plants, dated September 11, 1987;

   iv. Vermont Yankee letter to the USNRC, Supplement to Vermont Yankee Response to NRC Bulletin No. 87-01: Thinning of Pipe Walls in Nuclear Power Plants, dated December 24, 1987;

   v. USNRC Generic Letter 90-05, Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2 and 3 Piping, dated June 15, 1990;

   vi. Vermont Yankee letter to the USNRC, request from code relief for use of ASME Code Case N-597, as an alternative to analytical evaluation of wall thinning;

   vii. USNRC letter to Vermont Yankee, Vermont Yankee Nuclear Power Station—Relief request for use of ASME code case N-597 as an Alternative Analytical Evaluation of wall thinning (TAC No. MB1530) dated July 27, 2001. NVY 01-74;

   viii. VY memo: J.F Calchera to OEC (R. McCullough), subject: response to commitment item: ER-990876_01, Reevaluate Feedwater Heater Inspection Program to address Ownership, dated April 25, 2000.

Industry guidance and other records that were used for interpreting VY position regarding license renewal include:

[22] Items i., ii, iii, iv, and viii listed as commitments were not provided to NEC but were only referenced in Entergy's program level documents, and therefore were not directly reviewed. They do not appear on Entergy's Appendix A, licensee renewal list of commitments, but are listed in program level documents that were valid until March 15, 2006. No evidence of withdrawal, modification, or otherwise changes to these commitments was provided to NEC.

ix. Flow accelerated corrosion in power plants TR-106611-R1, published by EPRI in 1999;

x. Official Transcript Advisory Committee on Reactor Safeguards subcommittee on Power Uprates November 30, 2005;

xi. RAI SPLB-A-1 (LR001576);

xii. Section 12-2 Wear rate analysis (Excerpt from an EPRI report);

xiii. VYNPS License renewal Project Aging Management Program Evaluation Results. (NEC00113191)

B. Implementation of the Flow Accelerated Program in accordance with the CLB.

I reviewed the following documents to ensure the implementation of the FAC program in accordance with the CLB:

xiv. ENN-DC-315, Rev. 1, "Flow Accelerated Program;"

xv. VY-PP7028, Piping Flow Accelerated Corrosion Inspection Program;

xvi. VY –PP7028, FAC Inspection program PP 7028- 2007 Refueling outage;

xvii. VY -PP7028, piping inspection program, FAC inspection records for 2005 refueling outage;

xviii. ENN-CS-S-008, rev 0, effective 9/28/2005, pipe wall thinning structural evaluation;

xix. DP-0072.

C. Review of Inspection Histories, EPRI Reviews, Quality Assurance Reports, Cornerstone Roll-ups, Focused Self assessments, Condition Reports, and Independent Assessments, and NRC Inspection Reports.

In addition, I reviewed inspection histories, condition reports, quality assurance reports, and one cornerstone report rollup on trending in the FAC Program (2003)-

through October, 2006), NRC Inspections, and various revisions to VYLRP subsections and revisions. The list included the following:

xx. Focused Self Assessment Report, Vermont Yankee Piping Flow Accelerated Corrosion inspection report, Condition Report LO-VTYLO-2003-0327;

xxi. Audit No. QA-8-2004-VY1, Engineering Programs, dated 11/22/2004;

xxii. EPRI review of Vermont Yankee Nuclear Power Flow-accelerated corrosion, dated February 28, 2000;

xxiii. CR –VTY-2005-02239;

xxiv. Cornerstone Rollup update last dated 10/23/2006;

xxv. VYNPS License Renewal Project Aging management Program Evaluation Results.23

D. <u>Current status of the FAC Program with respect to the licensing basis.</u>

1. The current licensing basis goal is to preclude negative design margin or pipe rupture due to Flow-Accelerated Corrosion and is centered around use of EPRI document NSAC 202L. The guidance is specifically endorsed by the NRC under NUREG 1801, which calls for a three prong approach to minimize uncertainties:

(1) Use of a model such as CHECWORKS [with precision in data collection, examination, and frequency];

(2) Use of sound engineering judgment in selecting inspection points that are independent of CHECWORKS; and

[23] These documents were typically provided to NEC in fragments, with no title page, no document date, no record of whether the documents were current and had superseded others, and no signature or references to the author.

(3) Use of industry events that have potential relevance to VY in material condition, design parameters, and operating history.

There are numerous FAC-related failures throughout the industry. Examination of the OECD Pipe Failure Data Exchange Project (OPDE) database provides that information.[24]

2. To accomplish the licensing basis goal, the FAC Program needs explicitly to include each of the following ten elements under the specific Generic Aging Lessons Learned (GALL) Report:

1. Scope
2. Preventative actions
3. Parameters monitored or inspected
4. Detection of aging effects
5. Trending
6. Acceptance criteria
7. Corrective actions
8. Confirmation processes
9. Administrative processes

[24] Exhibit NEC-UW_15, NucE 597D-Project 1, Data Collection of Pipe Failures occurring in Stainless Steel and Carbon Steel Piping. provides industry wide data on FAC failure. Pages 20 and 30 include a failure rate for BWR plants. The probabilistic risk assessment for BWR plant FAC failures is reported as 10E-5 (higher than reactor accident threshold PRA for Design Basis Accidents).

10. Operating experience[25]

3. Implementation of these ten elements is accomplished under formal program-level procedures. Successful implementation requires actions in sequence that are constructive to yielding the highest predictability of wall thinning and the most certainty in ranking test points for inspection on a routine that collects wear data in a timely fashion, then adjusts the selection scope based upon multiple trending of data, along with incorporation of changes to the plant.[26]

4. [redacted].[27] The record indicates that the Vermont Yankee Nuclear Power Station ("VYNPS") FAC program only partially implemented its licensing basis requirements to achieve a successful FAC program and that Entergy was aware of the problematic state of the program for many years.[28]

5. The self-identified deficiencies in Entergy's current VYNPS FAC Program are identified in multiple documents. Perhaps most significantly, it appears that Entergy was first notified by EPRI as early as 2000 that it had not been fully updating the CHECWORKS model in use at VYNPS with plant inspection data collected or plant modifications performed during previous inspections.[29] Entergy apparently ignored the warning. More troubling is that Entergy continued to be in non-compliance with its

[25] Exhibit NEC-UW_06; [redacted]

[26] Exhibit NEC-UW_18 at 20, 30. This Exhibit provides industry-wide data on FAC failures. The high rate of failure in BWR plants underscores the need for precision in implementing an FAC program.

[redacted]

[28] Exhibits NEC-UW-05 at NEC017893-912: Exhibit NEC-UW-09 at NEC038422.

[29] Exhibit NEC-UW-10.

licensing basis through the years 1999-2006. This deficiency was again noted in late 2004 under an internal quality assurance audit, and two Condition Reports were written.[30]

6. Relevant data apparently was not entered into the CHECWORKS model until the third quarter of 2006.[31] The October 23, 2006 rollup thus confirms that the model was not kept current during a seven-year period and suggests that susceptible locations may not have been inspected during this time period. This lengthy lapse significantly weakened the trending capability of the software, both during the lapse period and presently. It is also evident that EPU data was still being modeled and validated in 2008.[32] [redacted]

[redacted]

[redacted]

[30] Exhibit NEC-UW-11; Exhibit NEC-UW-12.

[31] Exhibit NEC-UW-09 at NEC038424 ("CHECWORKS models and wear data analysis updated with all previous inspections in 3rd quarter 2006.").

[32] Exhibit NEC-UW_14, Email letter

[33] Exhibit NEC-UW_17.[Proprietary], Entergy: Letter to NRC re: Extended Power Uprate Response to Request for Additional Information..

[redacted][34]

In spite of Entergy's commitment, the required additional susceptibility scoping analysis is not apparent to NEC in information provided.

7. From 1999-2006, the plant was essentially operating in a state in which component wear was improperly trended and pipe conditions were actually unknown. Reliance on CHECWORKS for this time period for predicting grid points, ranking susceptible components, and inspecting new points was therefore virtually without technical or empirical value. Without proper trending, the predictability goal of CHECWORKS is lost; it essentially became a data collection repository.

8. During the years 2000-2006, the VYNPS FAC program apparently used an outdated version of the CHECWORKS software. As far back as 2000, EPRI recommended that VYNPS update to the current version of the software, but the recommendation was not implemented until 2006.[35] Entergy's failure to update the CHECWORKS model in a timely fashion makes data comparison between operating cycles more difficult.

9. In 2004, at least four VYNPS components, including the condensate system and the extraction steam systems, were determined to have "negative time to Tmin," meaning that wall thinning was being predicted as beyond operability limits and should be considered unsafe with potential rupture at anytime.[36] "Negative cycles of operations,"

[redacted]

[35] Exhibit NEC-UW-10.

[36] Exhibit NEC-UW-05 at NEC017893.

meaning wall thinning *beyond* acceptable code limits, were also predicted. The hours negative to the next inspection were substantial—predicting potential code violation or failure could have occurred 3000+ hours previously to October 23, 2006. It is surprising that the Licensee apparently did not write condition reports for this condition. I do not believe that NEC received any notice of Condition Reports relevant to this significant indication by CHECWORKS predicting substantial wall thinning beyond code limits to occur with negative margin of this magnitude. This issue is particularly troubling given that the equipment failure event is unpredictable, and catastrophic when wall thinning is beyond acceptable limits. Despite CHECWORKS' prediction of wall thinning, the plant continued to operate. I have not seen any inspection or audit discussion of this situation. It does, however, appear on the RFO 24 Inspection Plan,[37] oddly with the same number of hours of negative time to Tmin, even with the plan including wear data observed of 30% increase at Quad Cities and Dresden after the up-rate.[38]

10. The VYNPS FAC program was deemed unsatisfactory under quality assurance review dated November 22, 2004, and two condition reports were written.[39] On page 5, the report notes the need for program management to ensure "update of susceptible piping to be identified and modifications to be incorporated."[40] In addition, the report notes that cross-discipline review required by procedure had not been performed.[41]

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[37] Exhibit NEC-JH_43 at 5.

[38] Id. at 41.

[39] Exhibit NEC-UW-11 at NEC038514.

[40] Exhibit NEC-UW-11 at 5.

[41] Exhibit NEC-UW-11.

11. The 2006 cornerstone report shows a number of indicators as yellow, with lists of open CR corrective actions, and a new CR written in August 30, 2006.[42] The report lists six corrective actions and four CRs that were written as early as 2003 that remain open.[43] These include references to a number of progress indicators, but authors of the report continue to express concern over the program and the slow progress to update the CHECWORKS model. I reviewed several of the listed condition reports, some more than four years old, and found no indication that corrective actions recommended in these reports were completed.

12. In addition, in 2005 a sixth CR was written, CR-VTY-2005-02239, stating "CHECWORKS predictive model for Piping FAC inspection program was not updated per appendix D of PP7028."[44] The first page of the CR includes a statement that this condition had no impact on the RFO 25 inspection scope – i.e., indicating that updating of CHECWORKS was not necessary for establishing scope of RFO 25. This assertion is another indicator that the VY FAC program was *prima facie* in noncompliance with its CLB.

13. A review of a focused self-assessment was performed. This assessment was called for under one corrective action from a condition report LO-VTYLO-2003-00327. The report identifies numerous issues that required or require action to bring the FAC program into compliance with the CLB. For example, the program susceptibility review report for

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[42] Exhibit NEC-UW-09 at NEC038419, NEC038422.

[43] Exhibit NEC-UW-09 at NEC038424.

[44] Exhibit NEC-UW-13 at 1.

2004 was not formal, and did not properly separate scope for ranking.[45] The report was not given an adequate review, nor placed in the document control system.

14. PP7028 notes plant modifications and inspection results as not updated since May 15, 2000.[46]

15. Ranking of small-bore piping was not done. With no ranking, the basis for selection of high susceptibility points for small-bore piping is not evident.[47] Procedural conflicts were identified with missing programmatic requirements.[48]

16. A flow-accelerated corrosion related pipe break associated with a 1" elbow, SSH (WO 06-6880), appears to have occurred in 3rd quarter 2006.[49]

17. Entergy apparently reduced the number of FAC inspection data points between the 2005 refueling outage and the 2006 refueling outage, in violation of its commitment to *increase* inspection data points by 50%. The 2005 refueling outage inspection called for 137 large-bore inspection points. The 2006 refueling outage inspection, presented to the ACRS on June 5, 2007, covered only 63 points.[50]

18. The 2006 refueling outage FAC inspection scope, planning, documentation, and procedural analysis all appear to have been performed under a superseded program document. ENN-DC-315 Rev.1 was effective March 15, 2006, superseding the PP7028

[45] Exhibit NEC-JH_44 at 17.
[46] Id. at 18.

[47] Id.

[48] Id. at 27.

[49] Exhibit NEC-UW-09.

[50] Exhibit NEC-UW-14.

Piping FAC Inspection Program.[51] Yet VY inspection plan for FAC Program PP7028 was approved on May 11, 2006, almost two months after the PP7028 program document was superseded.[52] This error potentially invalidates the baseline requirement of CHECWORKS, in accordance with NRC-endorsed guidance, to establish the as-found condition of components and piping.[53] The fundamental step of updating inputs is required in the NSAC 202L approach for FAC, and is a required step in the CHECWORKS instructions. Essentially, working to avoid procedure makes the results invalid. NSAC 202L calls for the baseline for the configuration change to be treated the same as new design.[54] Given the significant changes to the plant, a baseline pass with accurate inputs was necessary, and subsequent passes were necessary to establish the grid locations and high susceptibility inspection points.

19. No indication is provided that plant isometrics were updated as required as of 10/22/04.[55]

IV. Time needed to benchmark CHECWORKS for Post-EPU use at VYNPS

I agree with the testimony of Dr. Joram Hopenfeld that CHECWORKS is an empirical model that must be updated with plant-specific data. NUREG 1801 does not specify the number of years' data necessary to benchmark CHECWORKS, but does

[51] Exhibit NEC-UW-15 (ENN-DC-315); Exhibit NEC-UW_20(PP7028).

[52] Exhibit NEC-UW-05 at NEC017888.

[53] Exhibit NEC-UW-06 § XI.M17.

[54] Exhibit NEC-UW-06.

[55] Exhibit NEC-JH_44 at 19.

advise that a baseline must be established as noted above. [redacted] This requirement is reasonable given that each plant has unique characteristics and operating history. Separate industry guidance supports five to ten years of data trending.[57] Trending to the high end of the range is appropriate where variables affecting wear rate, such as flow velocity, have significantly changed, as at VYNPS following the 120% power up-rate.

Given the deficiencies in the current VYNPS FAC program discussed in this statement, trending under the program is of marginal value. In addition, substantial "negative margin" conditions were identified in scoping the 2005 FAC inspection—many of which were predicted because of the repeated missed inspections in previous outages (that, significantly, occurred prior to up-rate).

I do not agree that a prolonged period of data collection is not necessary to use CHECWORKS effectively at VYNPS after the 120% power up-rate because the predictive algorithms built into CHECWORKS are based on FAC data from many plants. VYNPS is unique in its approach of Constant Pressure Power Up-rate to 120%. Clinton is the only other plant to accomplish a one-step up-rate to 120% power and is a very different plant from VY. To my knowledge, out of 104 operating plants only six have

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[redacted]

[57] Exhibit NEC-UW-13 at 38 ("In order to establish a baseline for the plant's equipment performance and reliability, the operating history over the past 5 to 10 years is reviewed and trended.").

increased operating power by more than 15%.[58] Of this group, at least three – Clinton, Dresden, and Quad Cities – appear to have FAC-related issues.[59] The argument that CHECWORKS incorporates relevant industry data is difficult to accept when so few plants are operating under analogous conditions, and 50% of those have experienced FAC related problems.

The need to extend the period of data collection is further evidenced by the fact that the CHECWORKS model was not updated with plant-specific changes until after RFO 26. Furthermore, by inference from an inquiry by the Staff project manager to the resident inspectors office only two months ago, it appears the NRC was informed that the EPU up-rate conditions *were still being verified and the process was at this late date incomplete after two outages had passed* since EPU design was completed, licensed, and implemented. The apparent failure to update the program underscores the lack of benchmarking done to date regarding the CHECWORKS software, and demonstrates troubling failures by Entergy to adhere to their own procedural requirements and failure to honor commitments made to the regulator, for example, made to the ACRS in November 2005, regarding use of the tool and the applicant's intention to conduct benchmarking testing during RFO 25 and RFO 26.

Based on the foregoing, it is my opinion that seven or more cycles will be necessary to establish a credible benchmarking of CHECWORKS to VYNPS under up-rated operating conditions. [redacted]

[58] Exhibit NEC-UW_18, Union of Concerned Scientists, "Power Uprate History," July 12, 2007.

[59] Exhibit NEC-UW-05.

[redacted] It is also my opinion that benchmarking can only be accomplished after the current program deficiencies are corrected and a proper baseline is established.

[redacted]

ATTACHMENT B

NEC-UW_01

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

PRE-FILED DIRECT TESTIMONY OF ULRICH WITTE REGARDING NEC CONTENTION 4

Q1. Please state your name and address.

A1. My name is Ulrich Witte. I reside on 71 Edgewood Way, Westville, Connecticut, 06515.

Q2. What is your educational and professional background?

A2. I obtained a BA in physics from the University of California, Berkeley in 1983. I have over twenty-six years of professional experience in engineering, licensing, and regulatory compliance of commercial nuclear facilities. I have considerable experience and expertise in the areas of configuration management, engineering design change controls, and licensing basis reconstitution. I have authored or contributed to two EPRI documents in the areas of finite element analysis, and engineering design control optimization programs. I have chaired the development of industry guidelines endorsed by the American National Standards Institute regarding configuration management programs for domestic nuclear power plants. My 26 years of experience has generally focused on assisting nuclear plant owners in reestablishing fidelity of the licensing and design bases with the current plant design configuration, and with actual plant operations. In short, my expertise is in assisting problematic plants where the regulator found reason to require the owner to reestablish competence in safely operating the facility in accordance with regulatory requirements. My experience is further detailed on my curriculum vitae filed with this testimony as Exhibit NEC-UW_02.

Q3. What is your understanding on NEC Contention 4 in this proceeding?

A3. NEC Contention 4 asserts that Entergy's plan for managing flow-accelerated corrosion (FAC) in plant piping fails to meet the requirements of 10 C.F.R. § 54.21(a)(3), *i.e.*, "fails to demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operations."

Q4. Did you prepare a report regarding this contention?

A4. Yes I did. My report is filed with this testimony as Exhibit NEC-UW_03. This testimony and my report provide, to the best of my knowledge, true and accurate statements of the facts and my conclusions regarding the issues relevant to NEC's Contention 4.

Q5. What materials did you review in support of your report and testimony?

A5. I reviewed the implemented FAC program and FAC inspection program, other inspection programs that Entergy has in place, and records and histories of these inspections. I also reviewed industry-wide standards for FAC programs, NRC data, information and reports, the CHECWORKS program and Entergy's commitments to upgrade the CHECWORKS model to EPU design conditions, inspection reports, EPU parameters, Plant Quality Assurance audits, Condition Reports, Corrective Actions, NRC regulations, EPRI review of the VY plant, Cornerstone Rollup, examples from other plants, and Entergy's application and the record (including reports, proposed programs, and testimony to the NRC Advisory Committee on Reactor Safeguards Subcommittee on Plant License Renewal) provided by Entergy or others in support of its application, including pipe wall thinning structural evaluation.

Further materials that I reviewed are specified in my attached report.

These are materials that are regularly used by experts in my field to assess aging management programs and flow-accelerated corrosion. I applied these materials in a standard manner that is routine with experts in this field.

Q6. Were these materials sufficient to allow you to form opinions and draw conclusions using your expertise?

A6. Yes, I had sufficient information to formulate the assessment stated in my report and maintain standards that are widely accepted by experts in this field. The Applicant did not, however, produce complete information to NEC regarding its methodology. My report notes where the Applicant's materials fail to provide sufficient information. As I have explained in my report, the information the Applicant produced is insufficient to validate its aging management program.

Q7. Please summarize your conclusions.

A7. In summary, I reached two conclusions:

First, the data collected under the current VYNPS FAC program during the post-EPU refueling outages scheduled prior to the expiration of the current VYNPS license is insufficient to benchmark CHECWORKS to VYNPS's post-EPU conditions. The Applicant states without ambiguity that the present program is sufficient not just for current operations and maintenance of the plant, but for the license renewal period as well. The record of a historical regulatory compliant program indicates otherwise.

Second, the current VYNPS FAC program does not appropriately implement industry guidance, and does constitute an adequate aging management plan with respect to FAC.

More specifically, my conclusions are:

- Contrary to EPRI recommendations, from 1999-2006, Entergy apparently failed to update the CHECWORKS model in use at VYNPS with plant inspection data or information concerning plant modifications. This lengthy lapse may have significantly weakened the trending and predictive capability of the software, both during the lapse period and presently. The update to incorporate EPU design data appears to still be in progress as of February 2008.

- Contrary to EPRI recommendations, the VYNPS FAC program apparently used an outdated version of the CHECWORKS software during the years 2000-2006.

- In 2005, the CHECWORKS model predicted wall thinning close to or exceeding acceptable code limits at several locations, but Entergy apparently produced no Condition Reports addressing these imminent potential pipe ruptures, or at least has not produced such reports to NEC in this proceeding.

- Numerous internal Entergy reports label the VYNPS FAC program unsatisfactory. The program was deemed unsatisfactory in the 2004, and the 2006 cornerstone report expressed concern about the program and specifically the continued slow progress in updating the CHECWORKS model.

- An FAC-related pipe rupture appears to have occurred during the third quarter of 2006.

- The 2006 refueling outage FAC inspection scope, planning, documentation and procedural analysis all appear to have been performed under a superseded program document, potentially invalidating the pre-EPU baseline for use of CHECWORKS.

- ~~Entergy apparently reduced the number of FAC inspection data points by fifty percent (50%) between the 2005 refueling outage and the 2006 refueling outage, in violation of its commitment to *increase* inspection data points by fifty percent (50%).~~

Further detail and supporting information is in my attached report.

I declare pursuant to 28 U.S.C. § 1746 under penalty of perjury that the foregoing is true and correct.

Executed on April ___, 2008

____
Ulrich Witte

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

Ulrich Witte

At Westville, Connecticut, this 23rd day of April, 2008 personally appeared Ulrich Witte, and having subscribed his name acknowledges his signature to be his free act and deed.

Before me: Danette Broadhurst

Notary Public

My Commission Expires 8-31-2011

ATTACHMENT D

UNITED STATES
NUCLEAR REGULATORY COMMISSION

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

PRE-FILED REBUTTAL TESTIMONY OF ULRICH WITTE REGARDING NEW ENGLAND COALITION, INC.'S CONTENTIONS 2A, 2B AND 4

Q1. Please state your name.

A1. My name is Ulrich Witte.

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 concerning NEC's Contentions 2A and 2B 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 the Joint Declaration of James C. Fitzpatrick and Gary L. Stevens on NEC Contention 2A/2B – Environmentally-Assisted Fatigue (May 12, 2008) and exhibits thereto. I have also reviewed the NRC Staff Initial Statement of Position on NEC Contentions 2A, 2B, 3, and 4, the Affidavit of John R. Fair

Concerning NEC Contentions 2A & 2B (Metal Fatigue) (May 13, 2008) and exhibits thereto, the Affidavit of Kenneth Chang Concerning NEC Contentions 2A & 2B (Metal Fatigue) (May 12, 2008) and exhibits thereto, and the revised Affidavit of Dr. Chang provided on May 22, 2008.

I. <u>NEC's Contentions 2A and 2B – Environmental Assisted Metal Fatigue Analysis</u>

Q4. Please describe your qualifications to provide testimony concerning NEC's Contentions 2A and 2B.

A4. I have extensive experience in original stress analysis in qualifying Class 1 and Class 2 pipe and components, and applicable ASME codes as well as ANSI B31.1 codes, in particular in the design, analysis, construction, and qualification of Class 1 and 2 systems within the domestic nuclear industry. This experience includes, for example, original stress analysis for McGuire, Catawba, and V.C. Summers Power Plants. In addition, I have performed non-linear finite element analysis for a number of components and I am familiar with Swanson's computer algorithms such as ANSYS., RELAP, and other commercial analytical computer programs. Under contract to EPRI, I conducted detailed correlation studies of non-linear finite element analysis code predictions against actual in situ testing of piping and components at the Indian Point 1 Nuclear facility after the plant was closed. The results are published in EPRI Report Number 8480, — Seismic Piping Test and Analysis, 1980.

Q5. Do you agree that Entergy's "confirmatory" CUF_{en} analysis of the feedwater nozzle fully incorporates thermal fatigue history for the feedwater nozzles?

A5. No. The NRC questioned the Applicant's "simplified analysis" with respect to the Feedwater nozzle as part of Request for Additional Information (RAI) dated October 9, 2007, during NRC LR Audit. The Staff was unsatisfied with the responses by Entergy, dated October 19, 2007 and November 14, 2007. During a meeting with Staff on January 8, 2008, the Applicant committed to performing refined analysis on the Feedwater nozzle including the use of actual operational thermal fatigue histories, as opposed to derived histories from the GE Specification. Incorporation of operational histories of the Feedwater nozzle was made a formal commitment in BVY 08-008, dated February 5, 2008.

An operational event that results in an unanalyzed thermal transient to the reactor vessel is relevant and cannot simply be set aside as licensees did for some period of time. The event at Vermont Yankee (VY) was no exception. The causal relationship between the event as found in historical records and the consequences in terms of thermal shock is key. During the early years of plant start-up and operation there where many unplanned forced shutdowns. I found 42 for VY. Not exactly a silky smooth running reactor. Three were downright dangerous.

GE and the Licensee did not fully predict all of the events in their shutdown estimates. Hence, those that were outliers needed detailed analysis. During the mid-1980s and into the 1990s this fact came to light starting with NUREG 0599 and others. Operational events led to the need for careful and refined transient analysis. The simplified method was shown to be overly dependent on skillful and experienced engineering. New methods removed the uncertainties and doubts of accuracy in CUF and

CUF_{en}. Not just cycle counting but examination of derivative temperature changes forced on the reactor vessel, the associated safe end, and on, of course, the feedwater nozzle as well. I know, because I was required immediately to notify the Technical Support Center (the emergency response area assembling management to provide technical support) for just such an event occurred on December 26th, 1986, at 6am, which brought down another plant for many months, placing the plant under its emergency plan. There was a concern that the plant would never operate again.

Based upon my examination of Vermont Yankee's historical records and my own experience of the challenge of maintaining nuclear plant operational history beginning with plant start-up, it appears to me that major thermal transients have likely <u>not</u> been incorporated into the operational history, as referenced in the SER. This deficiency is particularly significant where the reactor vessel has experienced an unplanned and unanalyzed transient that was outside the engineered design basis. Occurrence of these events throughout the industry was not as uncommon as one might presume.

Assessment of transient impact to specific component life is required following such an event to reestablish fidelity with the plant's design basis and is accompanied by additional fatigue analysis. The outcome of the engineering analysis holds one of three possibilities: (1) severe damage has occurred to the nozzle or vessel (less likely), (2) no additional fatigue usage outside the GE Specifications has occurred (also not likely), or (3) some additional usage outside the GE Specifications has occurred and therefore the component life is shortened (likely). Assessment and incorporation of the assessment of these impacts into plant operating records is essential to providing a basis for effective aging management programs.

An example of an historical Vermont Yankee event with the potential to impact the useful life of a number of systems, structures, and components occurred on December 1, 1972. On that date, the reactor automatically scrammed when an internal fault on a startup transformer resulted in a loss of offsite power. The emergency diesel generators automatically started and connected to their electrical buses. The high pressure coolant injection (HPCI) system got an automatic start signal on high drywell pressure, but failed to start. The operators manually started HPCI. Three relief valves opened when reactor pressure increased to 1,130 pounds per square inch gauge. A fourth relief valve should have opened, but failed to do so. One of the three relief valves that opened chattered on its seat about 100 psig below its set point. The transient was significant as reflected by the fact that odds of a core melt from this single event were 1.4E-3. See, Exhibit UW-24. More significant to the issue of fully recovering the record of all transients and accurately incorporating them in assessing remaining fatigue life is the assessment of wear, damage, and stress on each relevant component during each significant transient event.

There are other examples of transients that appear to have not been incorporated as input in the refined fatigue analysis. During the period from 1973 through 1977, Vermont Yankee experienced 42 unplanned forced shutdowns. This is a significant number, and expended much of the fatigue life of the reactor vessel and feedwater nozzle. See Exhibit UW-25.

Of these 42 forced shutdowns, in 1976 Vermont Yankee experienced 10 unplanned reactor scrams. Exhibit UW-24. One of these, on July 6, 1976, occurred during surveillance testing when the air operator plunger on a relief valve did not move when air was applied. Two of the other three relief valves failed. The failures were traced to air operator diaphragms damaged during excessive heating. The damage was attributed to improper insulation in the proximity of the diaphragms and an extended operating cycle. Core melt frequency for this event was an astoundingly high number 6.25 E-2. Exhibit UW-24. Again, the event stressed a number of systems and impacted the fatigue life of numerous components.

I made a comparison of the Engineering Design Input document, EN-DC-141, Rev. 3 provided to NEC by Entergy, to available records contained in the following documents and as compared to the responses provided to Dr. Chang's questions contained in Exhibit UW-26, "NRC Audit 10/09/07, with responses provided 10/18/07."

It appears that, in Entergy's calculation of 60-year CUFs in its CUFen reanalyses, operational histories were not properly or accurately compiled and that instead of documented transients, *estimated* thermal transient histories were used to predict the number of Reactor Thermal Cycles for 60 years. Purported added conservatisms remain unqualified and unjustified. The estimates of thermal transients are provided on Attachment 1, Page 1 of 6, EN-DC-141, Rev. 3. See Exhibit UW-27 "Design Input Record, Environmental Fatigue Analysis for Vermont Yankee Nuclear Power Station."

Q6. Why is this of concern in assessing the validity of Entergy's CUFen reanalysis?

A6. Refined fatigue analysis fidelity largely turns on correct design inputs. The simplified Green's Function method challenged by Staff on January 8, 2008 and in other records, was essentially about uncertainty in assumptions and estimates. My observation is that this particular design input is an ungrounded estimate, an *assumption,* and not an actual historical number; any conclusion stemming from it, therefore, cannot be relied on without corroboration. Clearly, to proceed with estimates based on a flawed record of all transient events is not appropriate. The rationale provided for not using actual transient operational cycles as found in Exhibit UW-26 at sequential page no. 8 (Bates number NEC069994), is not valid in the event of a thermal transient event that was outside the original design basis. Entergy, has not shown that those events were incorporated.

Second, the estimated transient history – *assumption* – may or may not be conservative. As noted above, the plant experienced certain transients during its operational life from initial plant start up and testing, commercial operation, then uprate to 120% power beginning in 2004. Actual excursions, in particular those that appear to be outside the GE design specifications, should have been accounted for in the refined analysis. From the analysis provided, at least in the first example, they were not.

Third, considering Extended Power Uprate contributing factors such as increased flow, component modification, increased vibration, and increased core heat and neutron flux, the transients experienced by the plant beginning with power escalation to 120% should be given more weight in forecasting thermal transient cycles. There is no credible basis provided in the Applicant's analysis that justifies thermal cycle projections to 60 years.

In summary, by using estimated histories as opposed to actual history, specific transients that shorten the component fatigue life appear not to be acknowledged or included in the Applicants fatigue analysis, making the results including CUF_{en} unsubstantiated.

II. <u>NEC's Contention 4: Flow Accelerated Corrosion Plan</u>

Q7. Have you reviewed the initial statements of position, direct testimony and exhibits concerning NEC's Contention 4 filed by Entergy and the NRC Staff?

A7. Yes. I have reviewed Entergy's Initial Statement of Position on New England Coalition Contentions (May 13, 2008), and the Joint Declaration of James C. Fitzpatrick and Dr. Jeffrey Horowitz on NEC Contention 4 – Flow Accelerated Corrosion (May 12, 2008) and exhibits thereto. I have also reviewed the NRC Staff Initial Statement of Position on NEC Contentions 4, and the Affidavit of Kaihwa R. Hsu and Jonathan G. Rowley Concerning NEC Contention 4 (Flow-Accelerated Corrosion) (May 13, 2008), and exhibits thereto.

Q8. Entergy contends that you have no experience or expertise relevant to the testimony you have provided concerning NEC's Contention 4. How do you respond?

A8. I have extensive experience in development of engineering programs including controls for design change processes, configuration management programs and comprehensive initiatives in affecting operating nuclear power stations. These processes typically involve complex multifunction and multi-organization challenges. These programs are often mandated under federal regulations, or committed programs for a licensee to re-establish fidelity with its current design basis and license conditions. I have substantial experience in, for example, implementation and validation of NUREG 0737, "Clarification of TMI Action Plan Requirements," and was a principal manager in the successful restoration of Indian Point 3 from the NRC's Watch list, as well as Millstone Units 2 and 3. For the Tennessee Valley Authority, specifically the completion of the Watts Bar Nuclear Plant, I developed a program entitled "Program to Assure Completion and Quality." For Georgia Power's Plant Hatch, I developed and implemented a

Configuration Management Program, led in-house Safety System Functional Inspections, and an Electrical Distribution Function Inspection so as to prevent Plant Hatch from going on the NRC's watch list. For Northeast Utilities, I developed a multiple department and multi-function program to reestablish the fidelity of the design basis and licensing basis, including identifying, dispositioning and either eliminating or implementing over 30,000 regulatory commitments. My leadership in establishing and implementing these programs – successful initiatives – was well-received by the Licensee and well-received by the regulator. By their transparency to the community, they were generally accepted as improvements by the Licensee in protecting the health and safety of the public and minimizing risk to public assets.

As a seasoned engineer, manager, and problem solver, my expertise and track record demonstrate successfully implemented solutions to complex organizational, technical, or regulatory challenges in nuclear plant operations.

Applying my expertise in Engineering Design Control Programs, I note that Entergy's proposed Flow Accelerated Corrosion management program is based on use of a predictive modeling tool derived from an empirically based program with heavy reliance on engineering judgment, coupled with experience, oversight, and effective monitoring of FAC-related wear to certain vulnerable plant systems. My expertise in program management focuses on correct and effective implementation of the program and finding a record that is auditable, defendable against program requirements and transparent. To quote the NRC Staff's position regarding flow accelerated corrosion, "Corrosion is not an exact science. Due to epistemic and aleatory uncertainty, absolute wear rates cannot be determined...." NRC Staff Initial Statement of Position at 20. Thus the burden in constructing and maintaining an effective FAC program must emphasize reliance on engineering judgment, coupled with experience, oversight, and effective monitoring of FAC-related wear.

While I do not purport to be intimately familiar with the empirically based CHECWORKS algorithm, I can attest to sufficient expertise in evaluating the fidelity of a comprehensive FAC program. I believe that the parties and witnesses are not in dispute that an effective flow accelerated program is highly dependent on sound engineering judgment and precise implementation, including the program goal of effective management of the predictive results, so as to preclude wall thinning beyond acceptance criteria during the license renewal period.

A. Summary Rebuttal

Q9. Do you believe that Entergy's Flow Accelerated Corrosion Management Program as implemented to date will be adequate for purposes of aging management during the period of extended operation, as Entergy and the NRC Staff assert in their initial statements of position and direct testimony?

A9. No. Entergy asserts on page 34, 35, and 37 of their Intial Statement of Position to New England Coalition Contentions, that their intention to credit the existing program as demonstrated to be adequate with no changes planned. Staff underwrites this assertion as well on page 20 of the NRC Staff's Initial Statement of Position on New England Coalition Contentions. I do not agree the program as implemented to date is adequate.

NEC raised significant concerns regarding the Flow-Accelerated Corrosion Program and asserted that the application for License Renewal submitted by Entergy for Vermont Yankee does not include an adequate plan to monitor and manage aging of plant equipment due to flow-accelerated corrosion during extended plant operation. The responses provided in summary disposition as well as Entergy's Reply and Staff's Reply do not address NEC's concerns and in fact raise troubling new concerns beyond simply the sufficiency of the Vermont Yankee flow-accelerated corrosion program as presently credited for license renewal.

The Applicant's response summarized during motion for summary disposition is that it's *present* FAC program is consistent with industry guidance including EPRI NSAC 202L R.3 and that the use of the CHECWORKS model is a central element in the FAC program implementation. The Applicant stated that it is relying on its current program for FAC management for the license renewal period, and "furthermore, the FAC program that will be implemented by Entergy is the *same program* being carried out today... [and] will meet all regulatory guidance." See Entergy Reply at 34.

Entergy represents that it will rely on its current FAC management program for purposes of FAC management during the license renewal period, that no changes to this program are planned, and that this program complies with EPRI guidelines. *See,* Entergy's Initial Statement of Position on New England Coalition Contentions at 34 ("The current FAC program, which will be used during the license renewal period, meets industry *practice as reflected in NSAC-202L...").* My review provided in pre-filed testimony shows that Entergy's current program is not in compliance with EPRI guidelines.

Q10. Entergy asserts on page 34 of its Initial Statement of Position that "the program has been reviewed, audited, and inspected with only minor, mostly

administrative issues identified," and discounts its own Quality Assurance audit, which declared the program "unsatisfactory." How do you respond?

A10. I believe that these statements indicate that Entergy may have ignored or misconstrued the fundamental requirements of 10CFR Part 50, Appendix B, "Quality Assurance Requirements for Nuclear Power Plants." It appears that federal requirements for Quality Assurance (QA) are being set aside. Quality Assurance Division Audit No. QA-8-2004-VY-1 declared the Flow Accelerated Program "unsatisfactory," submitted two Condition Reports, and found five findings and seven areas of improvement. *See,* Exhibit NEC-UW_09 at 2. Yet Entergy's Initial Statement of Position interprets the 38-page document as containing "only minor, mostly administrative issue[s]." Entergy Initial Statement of Position at 34.

Furthermore, the Entergy asserts this single analytical tool for predicting unacceptable wall thinning should, as policy, be set aside as it was for four components, See Exhibit NEC-UW_20 at 5 of 14. Thus the Entergy provides a second indicator where the Licensee obliquely waived Appendix B requirements for Quality Assurance. See Entergy Statement of Initial Position at 48.

That again is misapplication of the requirements of Appendix B, which is particular to the Flow Accelerated Program, where the Applicant's only defense to its failure to prepare condition reports associated with unacceptable wall thinning, a prediction derived from its own analysis, is somehow that this component shown not to be meeting quality standards is deemed acceptable "as is" until the next outage. Therefore, there are two indications of a troubling and clearly deep-seated failure to properly implement the requirements of a compliant Quality Assurance Program. Appendix B to

10 CFR Part 50 requires among other things, Section III, "Design Control; and Section XVI, "Corrective Action" The latter section of the rule includes the following:

> Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to the appropriate levels of management.

Quality Assurance requirements are not a *practice* that may or may not be voluntarily implemented by the Licensee, but are in fact are <u>regulatory</u> requirements promulgated under federal rules. The Applicant incorrectly asserts that a failure theoretically predicted by the CHECWORKS model is somehow treated differently than a failure predicted by actual inspection data. The Applicant is incorrect in assuming that a failure predicted by CHECWORKS does not meet the threshold for a condition report, with timely follow-up or corrective action, as fundamentally required under Appendix B. The Licensee has no regulatory grounds to escape a determination of potential failure by reason of its assertion that "if a planning tool such as CHECWORKS .....determines a *theoretical* conclusion... as such no condition reports are required." See Entergy Statement of Initial position at 48. This improper rationale is essentially analogous to a Licensee *ignoring* a Technical Specification requirement calling for declaration of a component or system to be classified as inoperable and a Limiting Condition of Operation started if a surveillance is missed. In the analogous situation, a component is administratively (theoretically) declared inoperable, although its actual functionality is unknown.

The consequences of the Licensee's apparent policy regarding Appendix B requirements, for Vermont Yankee's Flow Accelerated Corrosion Program are significant and have broad implications to multiple programs relied upon for renewal. Essentially, following the Licensee's logic every program can be viewed as theoretical when it is intended to be a predictive tool. The implications of Entergy's statements are profound and raise questions regarding credibility of all the Aging Related Management Programs proposed and Entergy's actual intentions for monitoring, and maintaining the plant if the license is extended.

Q11. Has applicant provided in its response any reasonable assurance that pipe thinning beyond code limits will not occur in the period between outages?

A11. No. Quite to the contrary, the applicant has stated at page 48 of its Initial Statement of Position, in reference to page 5 of 14 of PP7028 Piping Inspection Program, Exhibit NEC-UW_20, that wear rates predicted to exceed code limits will not be acted upon until the next outage. Based on statements made by the Applicant regarding pipe thinning predictions including negative time to inspect (described as negative T_{min} in the document) and predictions of unacceptable wear rates leading to thinning beyond code limits prior to the next outage, coupled with the decision to not prepare condition reports (or an analogous report consistent with requirements of a corrective action program as part of Appendix B), it is my opinion that reasonable assurance is not provided, and that the NRC Staff erroneously concluded that the program is complete, correct and adequate.

Therefore, my opinion is that the staff erroneously concluded that the program is complete, correct and adequate.

Q. 12 Does Entergy's Initial Statement of Position resolve the programmatic weaknesses you identified in your direct testimony, including open corrective actions, stale open action items from condition reports, and the negative assessment of the program stated in the 2006 cornerstone roll up report?

A12. No. Entergy characterizes the issues I have identified as shortcomings in the documentation paperwork with no substantive implications. I disagree. Any one of the Quality Assurance findings are significant. For example, a classic indictor of a problematic program is age of open corrective actions. A second indicator is number of Condition Reports, and number of extensions planned and then postponed to implement necessary actions to maintain the program current. Data drawn was sometimes more than fifteen years old.

Entergy expends much discussion, largely on a generic basis, on what ought to constitute a good FAC program. Entergy Statement of Initial Position at 36. However, Entergy does not respond to or take into consideration the VY's actual repeated historical failures to implement the FAC program from 1999 to the present day, which I have identified in my report, filed in this proceeding as Exhibit NEC-UW-03. With few exceptions, these numerous programmatic failures go unchallenged by Entergy.

Most significantly, successive implementation of CHECWORKS to current plant design inputs is undisputed as a mandatory element of the program, as required under NSAC 202L rev. 2 and rev. 3. Entergy makes no claim that this was consistently done.

Successive data passes at appropriate intervals, with scope selection, current operating conditions etc, taken into consideration are a fundamental element to identifying appropriate grid selection points, and trending of wear items. However, this obligation was consistently ignored for many years and at best done in fragments for many outages. See Exhibit NEC-UW_03, "Evaluation of Vermont Yankee Nuclear Power Station License Extension." This approach places the reviewer in the untenable position of having to look a look at wear data for trends with only very limited data points and then speculate as to whether the data set is sufficient. This approach is invalid.

<u>**Detailed Review of Entergy and Staff Reply**</u>

Q13. Do you take issue with the general merits of the approach to FAC management recommended in NSAC 202L?

A13. No. My focus is strictly on the adequacy of the implementation of NSAC 202L at VY.

Q14. On Page 38 of its Initial Statement of Position, Entergy makes the following assertion regarding FAC Susceptibility review: "the only CHECWORKS inputs affecting FAC wear rate that need to be changed to model uprate conditions were the flow rate and the temperature. These were updated at VY upon implementation of the EPU." Do you agree that flow rate and temperature are the only inputs that were necessary to incorporate into the model?

A14. No. I disagree. Identification of the added inputs should be made, incorporating the results of all pertinent susceptibility analyses. Apparently, this has not been done. First, Exhibit E4-32 is a copy of a susceptibility analysis performed by Entergy in 2005. This analysis was performed fully five years after the previous analysis was completed in 2000. This five year gap is found by examining the dates associated with the 2005 Susceptibility analysis. Numerous changes to the plant occurred between 2000 and 2005. For example, in 2003, the reactor recirculation and residual heat removal piping was replaced. See, Exhibit NEC-UW_27 at 6, Attachment 1. Second, operational factors (such as TECH

SPEC changes, configuration changes, and material changes) should have triggered a new susceptibility analysis well before the analysis performed in 2005.

In brief, beginning in 2004, substantial plant modifications were performed, including system modifications etc, yet a current Susceptibility Analysis was not performed until 2005. The premise that only flow rate and temperature input changes were needed is not properly supported and incorrect.

It is apparent that Vermont Yankee's FAC program management was broken from February 28, 2000 through October 25, 2005 based upon lack of Susceptibility Analysis alone. A comparison of program scope for piping inclusion, exclusion, small bore, large bore, fluid type etc, should have been incorporated into the FAC Program under the station Engineering Design Controls program on an ongoing basis—essentially any time a plant modification, system function change, or operational change was contemplated. Based upon the Applicant's information provided on page 38 of Entergy's Statement of Initial Position, as well as the Table 2 of Exhibit E4-32, the susceptibility analysis was set aside for more than five years, losing both continuity and assurance that all modifications have been evaluated and taken into consideration.

Proper grid point selection, proper sampling, proper frequency and the consistent integration of new data all serve to remove speculation and uncertainty in the accuracy of CHECWORKS. This fact by itself provides the impetus for a "new baseline," especially in light of the fact that a current baseline is, for all practical purposes, lacking. In conjunction with the relative uniqueness of the CPPU power uprate—chemistry changes, geometry changes, and of course velocity changes, the need for a "new baseline" is compelling. The strength of the CHECWORKS and the NSAC 202L methodology endorsed in the GALL Report, is in its successive passes with tight control of changes in requisite input variables. These core elements have yet to be implemented.

In 2005, Entergy relied on ancient susceptibility data for component selection points, such as small bore piping from data circa 1993. *See* Exhibit NEC-UW_20 at page 12 of 14. Five small bore points were selected that had never been inspected previously, indicating loss of control of the program. Entergy's defense of this methodology raises significant doubt as to the efficacy of the current program, and therefore the FAC program for the license renewal period.

A lack of a timely susceptible review can only serve to skew the results appropriate selection of specific wear points. An updated and inclusive Susceptibility Review should definitely have been required by NRC Staff in their review. It apparently was not.

The Susceptibility review did not appear to address wear points associated with plant modifications, and based upon the descoping of the inspection, even after recommending by engineering judgment, to include certain points they were not. *See* Exhibit E4-38 referenced in Entergy's Statement of Initial Position at page 39.

Q15. On page 39 of its Initial Statement of Position, Entergy states that in 2007, RFO 26, the first outage since the EPU, the inspection scope was a total of 63 inspections performed, including 49 large bore inspections. Do you believe that Entergy met its commitment to increase the scope of inspection by 50%?

A15. No. It is apparent on reviewing the record that Entergy first reduced the effective inspection scope and then enlarged it, in the process offsetting any "increase." A mirror analogy would be the retail store that raises its prices on certain goods, prior to offering them at a sale discount.

Entergy's commitment to increase the number of inspection points by 50% was made in response to an RAI, acknowledged in Entergy's Statement of Initial Position at 39, but this commitment was tacitly fulfilled by increasing the number of inspection points for RFO 26 only after decreasing the number of inspection points (by descoping) for RFO 25. The Scoping document for RFO 25 contained significantly more inspection points. See, Exhibit NEC-UW_20, "PP7028 Piping FAC Inspection Program FAC INSPECTION PROGRAM RECORDS FOR 2005 REFUELING OUTAGE." On page 20, it states "The planned 2005 RFO inspection scope consists of 0137 large bore components at 16 locations…[a]lso, any industry or plant events that occur in the interim may necessitate an increase in the planned scope." In addition, criteria for inspection of components outside of CHECWORKS grid selection is articulated to include points simply because of the lengthy intervals since previous inspections. These include Feedwater piping, and Mainsteam piping. Id. at 3.

However, the number called for in the above scoping document is considerably more than the actual number of large bore components reported to be inspected during RFO 25, as in Exhibit E4-38, where the Applicant notes that it limited its inspection to 27 large bore points. The actual inspection of 63 large bore points for RFO 26 is about ½ of the number of planned inspection points for RF0 25, not 50% more.

Q16. Entergy disagrees with your statement in direct testimony that "trending to the high end of the range [for bench marking] is appropriate where variables

affecting wear rate, such as flow velocity, have significantly changed, as at VYNPS following the 120% power up-rate...". How do you respond?

A16. Entergy questions the relevance of the report brought forward in my direct testimony in support of this statement. The report in question is "Aging Management and Life Extension in the U.S. Nuclear Power Industry," Exhibit NEC-UW_13, or the "Chockie Report." Entergy asserts that this report does not support trending to the high end of the range where variables such as flow velocity etc have significantly changed, because it is not industry guidance, but a report produced at the behest of the Petroleum Safety Authority of Norway regarding aging management and life extension in the U.S. nuclear power industry.

The Chockie Report most certainly assimilates industry guidance, including regulatory rules and implementation of those rules, and compiles aging programs strictly with respect to the United States domestic nuclear power plants. On page 38, it answers exactly what is required if there is no pre-existing baseline, as is the case for Vermont Yankee. The use of the report by the Norway Petroleum Safety Authority has no bearing on its content. The report is on point to Contention 4.

The Chockie Report is applicable to the question of what constitutes an adequate baseline. Entergy assumes that its present baseline is adequate. I believe after examination of the failure to adequately implement the program, that VY does not have an adequate baseline. The Chockie Report is a concise primer on the effective implementation of NSAC 202L, including CHECWORKS, and by inference impeaches Entergy's Application as well as the adequacy of NRC Staff Review.

Q17 Do you agree with Entergy's statement contained in a single paragraph on page 45 of Entergy's Initial Statement of Position that the following eight claims you made in your direct testimony have no merit?

a. **"that data from previous FAC inspections (prior to the EPU) were not entered into the CHECWORKS database (NEC-UW_03 at 2, 3, 6, 7-8, 15, 16, 17);"**

b. **"that CHECWORKS was not updated with the uprate parameters (id. at 5, 23);**

c. **that, for the period 2000-2006, VY failed to use a current version of CHECWORKS (id. at 6, 17);"**

d. **"that four components were predicted in 2004 to have wall thinning beyond operability limits (id. at 17-18, 22);"**

e. **"that open corrective actions identified in condition reports may not have been completed (id. at 3-4, 18-19);"**

f. **"that ranking of small bore piping was not done (id. at 8, 20);"**

g. ~~**"that the number of inspection points were reduced after the 2005 outage (id. at 7, 8, 20); and"**~~

h. **"that the 2006[1] refueling outage inspection "scope, planning, documentation, and procedural analysis appear to have been performed under a superseded program document" (id. at 5, 7, 20-21)."**

A17. No. I disagree. Entergy states that these claims have no merit but does not actually refute them, or specifically address the majority of the documents I cite in support of my direct testimony. Entergy's reply to my direct testimony consists primarily of conclusory denials.

Q18. *Does this conclude your rebuttal testimony?*

A18. Yes

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

UWitte

Ulrich Witte

At Westville, Connecticut, this 6th day of June, 2008 personally appeared Ulrich Witte, and having subscribed his name acknowledges his signature to be his free act and deed.

Before me:

____

Notary Public

My Commission Expires ________________

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 MOTION TO FILE CORRECTIONS TO EXHIBITS AND TO WITHDRAW CERTAIN TESTIMONY OF ULRICH WITTE 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 the 27th of June, 2008.

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