NEI

NUCLEAR ENERGY INSTITUTE

James H. Riley
DIRECTOR, ENGINEERING
NUCLEAR GENERATION DIVISION

August 22, 2006

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

SUBJECT: Revised Steam Generator Management Project Guidance and Information Documents

PROJECT NUMBER: 689

The purpose of this letter is to transmit current versions of several Steam Generator Management Project (SGMP) documents for your information and to submit a draft SGMP guideline for NRC review. The various documents are described below.

- SGMP has issued Revision 2 to its Steam Generator Integrity Assessment Guidelines. A proprietary and non-proprietary copy of this document is enclosed for your information.
- The PWR Steam Generator Examination Guidelines are currently under revision. In previous communications we agreed to provide draft copies of revisions to EPRI SGMP guidelines for your review. A proprietary and non-proprietary draft copy of Revision 7 to the PWR Steam Generator Examination Guidelines is enclosed. We request that you forward any comments you may have on the draft guideline to Steve Swilley at EPRI (sswilley@epri.com) by September 25, 2006, in order to support our publication schedule.
- It has been NEI's practice to send copies of SGMP interim guidance letters to the NRC as they are issued. These letters remain active until the implementation deadline of the SGMP Guideline which they affect. As a result, some of the interim guidance letters that we have sent you in the past may no longer be active. Copies of a complete set of active interim guidance letters are enclosed for your information.
- In the past, NEI has not submitted copies of SGMP information letters to the Staff. In our meeting on July 12, 2006, we promised to send you copies of all the active SGMP information letters. Copies of these documents are enclosed for your information.

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The SG Integrity Assessment guidelines and Steam Generator Examination Guidelines contain proprietary information that is supported by the signed affidavit in Enclosure 3. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the consideration listed in paragraph (b)(4) of Section 2.790 of the Commission's regulations. Accordingly, we respectfully request that the information, which is proprietary to EPRI, be withheld from public disclosure in accordance with 10 CFR 2.790. Non-proprietary versions of the SG Integrity Assessment and Steam Generator Examination Guidelines are also enclosed.

None of the other enclosed letters are proprietary.

Consistent with previous submittals supporting NRC review of EPRI's SGMP guidelines, we believe any NRC staff review of the Steam Generator Examination Guidelines is exempt from the fee recovery provision contained in 10 CFR Part 170. This submittal provides information that may be helpful to NRC staff when evaluating licensee implementation of the Steam Generator Program and its associated technical specifications. Such reviews are exempted under §170.11, Exemptions, Subpart (a) (1) (iii). This provision states, (a) "No application fees, license fees, renewal fees, inspection fees, or special project fees shall be required for...(1) A special project that is a request/report submitted to the NRC--(iii) As a means of exchanging information between industry organizations and the NRC for the specific purpose of supporting the NRC's generic regulatory improvements or efforts".

If there are any questions on these matters, please feel free to contact me at 202-739-8137; jhr@nei.org.

Sincerely,

James H. Riley

James H. Riley

Enclosures

c: Mr. Allen Hiser, NRC
Mr. Emmett Murphy, NRC
Mr. Ken Karwoski, NRC
Ms. Michele Honcharik, NRC

Enclosure 3

Proprietary Affidavit

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

DAVID J. MODEEN
Vice President and
Chief Nuclear Officer
Nuclear

August 11, 2006

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

Subject: Request for Withholding of the following Proprietary Documents:

(i) Report No. 1012987, "EPRI Steam Generator Integrity Assessment Guidelines: Revision 2, July 2006"; and

(ii) Draft Report No. 1013706, "EPRI Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 7, July 2006".

To Whom It May Concern:

This is a request under 10 C.F.R. §2.390(a)(4) that the NRC withhold from public disclosure the information identified in the enclosed Affidavit consisting of the proprietary information owned by Electric Power Research Institute, Inc. ("EPRI") and identified above (the "Reports"). Copies of the Reports and the Affidavit in support of this request are enclosed.

EPRI desires to disclose, in confidence, the Reports for informational purposes to assist the U.S. Nuclear Regulatory Commission (the "NRC"). The Reports are not to be divulged to anyone outside of the NRC or to any of its contractors, nor shall any copies be made of the Reports provided herein. EPRI welcomes any discussions and/or questions relating to the information enclosed.

If you have any questions about the legal aspects of this request for withholding, please do not hesitate to contact me at (704) 595-2173. Questions on the content of the Reports should be directed to Steve Swilley of EPRI at (704) 595-2132.

Sincerely,

ELECTRIC POWER RESEARCH INSTITUTE, INC.

David J. Modeen
Vice President & Chief Nuclear Officer

Together . . . Shaping the Future of Electricity

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AFFIDAVIT

RE: Request for Withholding of the Following Proprietary Documents:

(i) Report No. 1012987, "EPRI Steam Generator Integrity Assessment Guidelines: Revision 2, July 2006"; and

(ii) Draft Report No. 1013706, "EPRI Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 7, July 2006".

I, DAVID J. MODEEN, being duly sworn, depose and state as follows:

I am a Vice President and the Chief Nuclear Officer of Electric Power Research Institute, Inc. whose principal office is located at 3420 Hillview Avenue, Palo Alto, California ("EPRI") and I have been specifically delegated responsibility for the above-listed reports that are sought under this Affidavit to be withheld (the "Reports"). I am authorized to apply to the U.S. Nuclear Regulatory Commission ("NRC") for the withholding of the Reports on behalf of EPRI.

EPRI requests that the Reports be withheld from the public on the following bases:

1. Withholding Based Upon Privileged and Confidential Trade Secrets or Commercial or Financial Information.

a. The Reports are owned by EPRI and have been held in confidence by EPRI. All entities accepting copies of the Reports do so subject to written agreements imposing an obligation upon the recipient to maintain the confidentiality of the Reports. The Reports are disclosed only to parties who agree, in writing, to preserve the confidentiality thereof.

b. EPRI considers the Reports and the proprietary information contained therein (the "Proprietary Information") to constitute trade secrets of EPRI. As such, EPRI holds the Reports in confidence and disclosure thereof is strictly limited to individuals and entities who have agreed, in writing, to maintain the confidentiality of the Reports. EPRI made a substantial economic investment to develop the Reports, and, by prohibiting public disclosure, EPRI derives an economic benefit in the form of licensing royalties and other additional fees from the confidential nature of the Reports. If the Reports and the Proprietary Information were publicly available to consultants and/or other businesses providing services in the electric and/or nuclear power industry, they would be able to use the Reports for their own commercial benefit and profit and without expending the substantial economic resources required of EPRI to develop the Reports.

c. EPRI's classification of the Reports and the Proprietary Information as trade secrets is justified by the Uniform Trade Secrets Act which California adopted in 1984 and a version of which has been adopted by over forty states. The California Uniform Trade Secrets Act, California Civil Code §§3426 – 3426.11, defines a "trade secret" as follows:

> "'Trade secret' means information, including a formula, pattern, compilation, program device, method, technique, or process, that: (1) Derives independent economic value, actual or potential, from not being generally known to the public or to other persons who can obtain economic value from its disclosure or use; and

AFFIDAVIT

(2) Is the subject of efforts that are reasonable under the circumstances to maintain its secrecy."

d. The Reports and the Proprietary Information contained therein are not generally known or available to the public. EPRI developed the Reports only after making a determination that the Proprietary Information was not available from public sources. EPRI made a substantial investment of both money and employee hours in the development of the Reports. EPRI was required to devote these resources and effort over a period of several years to derive the Proprietary Information and the Reports. As a result of such effort and cost, both in terms of dollars spent and dedicated employee time, the Reports are highly valuable to EPRI.

f. A public disclosure of the Proprietary Information would be highly likely to cause substantial harm to EPRI's competitive position and the ability of EPRI to license the Proprietary Information both domestically and internationally. The Proprietary Information and Reports can only be acquired and/or duplicated by others using an equivalent investment of time and effort.

g. EPRI is submitting with this Affidavit two versions of each Report: (i) a proprietary version; and (ii) a nonproprietary version from which the Proprietary Information has been redacted. EPRI requests that the Proprietary Information contained in the proprietary version of each Report be withheld from the public pursuant to 10 C.F.R. §2.390(a)(4).

2. Withholding Based On Draft Materials. EPRI requests that Draft Report No. 1013706, "EPRI Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 7, July 2006" (the "Draft Report") be withheld from public release based on the fact that the document is a draft document. Footnote 1 of 10 C.F.R. §2.390 specifically excludes draft materials from the documents which may be made available to the public. Because of the draft nature of the Draft Report and the potential for variance from the final version of such report, it could be confusing, as well as potentially misleading, to the public if this Draft Report were made publicly available.

I have read the foregoing and the matters stated herein are true and correct to the best of my knowledge, information and belief. I make this affidavit under penalty of perjury under the laws of the United States of America and under the laws of the State of California.

Executed at 1300 W T Harris Blvd, Charlotte, North Carolina being the premises and place of business of Electric Power Research Institute, Inc.

Date August 11, 2006

David J. Modeen [signature]

Subscribed and sworn before me this day: 11th day Date August, 2006

[signature] Notary Public My Commission expires August 23, 2009

Steam Generator Management Project (SGMP) Interim Guidance Letters

1	*8/31/01*	*Womack – Aug 2001*
2	*4/22/03*	*Womack – April 2003*
3	*8/18/03*	*Womack– IG 3Mile Tube Severe Event*
4	*3/16/04*	*Womack – March 2004*
5	*5/11/04*	*Womack – May 2004*
6	*5/17/04*	*Rev'd Chapter 10 R1*
7	*1/17/05*	*Interim Guidance (SIPC)*
8	*N/A*	*NEI 97-06 R2 Gaps Table*
9	*10/10/05*	*SGMP-IG-2005-02*
10	*10/18/05*	*SGMP-IG-05-03*
11	*11/11/05*	*Chapter 10 Secondary Side Maintenance*
12	*11/18/05*	*SGMP-IG-05-04*

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August 31, 2001

To: Steam Generator Management Program (SGMP) Utility Steering Committees
PMMP Steering Committee
Senior Representatives
Technical Advisory Group (TAG)

From: Lawrence F. Womack
Chairman, Steam Generator Management Program

Subject: Steam Generator Management Program's Interim Guidance for Utility Action in Response to Finding New Steam Generator Degradation

References:
1. NRC Letter, Sheron, Brian W. to Collins, Samuel J., through Zimmerman, Roy P., "Steam Generator Action Plan," November 16, 2000
2. Letter, Lawrence F. Womack to Steam Generator Management Program (SGMP) Utility Steering Committees, "Information Letter Concerning Lessons Learned from a Review of Recent Steam Generator-Related Issues," September 29, 2000
3. EPRI Final report, TR-107621-R1, *Steam Generator Integrity Assessment Guidelines*, Revision 1, March 2000

Introduction

The purpose of this letter is to provide you with interim guidance on the issue of utility response to newly identified degradation in their PWR steam generators. The information presented below was developed under the auspices of the SGMP IIG and its supporting subcommittees in response to a request by the NEI Steam Generator Task Force for the SGMP to respond to NRC-identified, industry-related issues presented in Reference 1. Reference 1 addresses steam generator-related technical and programmatic issues that were developed by the NRC in their evaluation of the regulatory process associated with steam generator tube integrity. The resulting action plan to address these issues, as indicated in Reference 1, is a result of consolidating NRC activities including: 1) the NRC's review of the industry initiative related to steam generator tube integrity (i.e., NEI 97-06); 2) GSI-163 (Multiple Steam Generator Tube Leakage); 3) the NRC's Indian Point 2 (IP2) Lessons Learned Task Group recommendations; 4) the Office of the Inspector General report on the IP2 steam generator tube failure event; and 5) the differing professional opinion (DPO) on steam generator issues. The action plan item that is the subject of this letter deals with newly found steam generator degradation. This issue is involved to some degree in more than one action plan item, but for clarity purposes the interim guidance provided by this letter addresses the specific issue as documented in the attachment "IP2 Task Group Recommendations," Item 21, of Reference 1.

Reference 2 provides some additional guidance on the subject of this letter. Reference 2 was industry's initial response in addressing technical issues that were being raised during the investigation of the tube failure event at Indian Point 2. Additionally, most of the issues identified in the NRC's action plan are already addressed in the EPRI Guidelines referenced in NEI 97-06. Further industry review of the NRC's action plan, along with discussions with the NRC on the subject of newly found steam generator degradation, has resulted in the development of additional guidance on this subject. This guidance is provided below.

Discussion

During the NRC's review of the IP2 tube failure event, the staff concluded that the degradation mode of axial PWSCC at the apex of a low row U-Bend, which resulted in the steam generator tube leak, should be considered as a new type of degradation for IP2. In this context, the NRC staff's position is that when a new type of steam generator tube degradation occurs for the first time, licensees should determine the implications on steam generator condition monitoring and operational assessments. The industry has guidance on development and maintenance of a degradation assessment. This guidance includes requirements to identify the condition of the steam generators as defined by the last plant outage and to anticipate the condition at the upcoming outage. This process should include an assessment of potential new forms of degradation with consideration as to their likelihood of occurrence. Historical information from other utilities should be used in the evaluation of potential mechanisms. However, the guidance documents do not address the actions to be taken when an unexpected damage mechanism is identified.

Conclusion

Based on the above information, interim guidance is presented as follows. For newly identified degradation modes that were not considered to be potential degradation mechanisms in the degradation assessment, the licensee should enter the issue into their corrective action program at a significance level that requires a root cause analysis to be performed, i.e., a Significant Condition Adverse to Quality as defined by 10CFR50 Appendix B. The degradation assessment and inspection plan should be reviewed and revised as necessary to ensure that the necessary data is available to allow the operational assessment to address potential effects of the new degradation mechanism. Corrective actions to bound the extent of condition, such as requiring additional inspections prior to unit restart, may be a result of this review. When developing corrective actions, consideration should be given to the effects of plant chemistry, individual plant operating experience, and other causal factors. Degradation that was expected but not previously active, which was addressed in the plant-specific degradation assessment and inspection plan, does not need to be entered into the plant corrective action program.

This interim guidance will be reviewed by the cognizant SGMP guideline committee and incorporated, if required, in the next revision of Reference 3 and other guidelines where appropriate.

Sincerely,

Lawrence F. Womack
Chairman, Steam Generator Management Program

cc Jim Riley, NEI
Alex Marion, NEI
Jeff Ewin, INPO
Gary Fader, INPO

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April 22, 2003

To: Steam Generator Management Program (SGMP) Utility Steering Committees
PMMP Steering Committee
Senior Representatives
Technical Advisory Group (TAG)

From: Lawrence F. Womack
Chair, Steam Generator Management Program

Subject: Interim Guidance on Steam Generator Tube Leak at Comanche Peak Unit 1

Backuround

On September 28, 2002, Comanche Peak Unit 1 entered 1RF09 seven days early due to a steam generator tube leak. The leaking tube was identified as R41 C71 in SG2 between AVB 3 and AVB 4 in the freespan region. This tube was inspected in 1999 (1RF07) and 2001 (1RF08) with no recordable indications reported. To inform the industry of this event and the related corrective actions that the utility had taken, SGMP issued an information letter dated October 25, 2002 under IIG Chair Kevin Sweeney's signature. It was stated in that letter that the SGMP NDE IRG will further study the issue for its generic implications and need for any interim guidance. The NDE IRG has completed its study and provides the following interim guidance that has been reviewed and endorsed by the SGMP IIG.

Problem Statement

Comanche Peak was using a specific calling criteria that required freespan indications to only be reported when they exhibited greater than zero percent through wall. All reported indications then required a historical review of the previous outage data to determine if changes occurred in signal phase or amplitude. Indications that exhibited change required diagnostic testing.

These criteria proved to be ineffective. There were two problems identified:

1. The requirement to only go back to the previous cycle when reviewing historical data was not sufficient to identify slow-growing ODSCC.
2. The leaking tube in the previous outage data was an indication measuring zero percent yet exhibiting flaw characteristics.

As a result of the discussion on Comanche Peak, the NDE IRG realized that additional guidance should be provided to the industry on change.

Recommendations

Issue 1

The industry recommendations are provided in several parts to accommodate the various scenarios that could exist from plant to plant.

1. For alloy 690 materials, the history review shall include look-back to the first in-service inspection (during the first ISI inspection look to pre-service inspection).
2. For alloy 600 thermally treated (TT), the history review shall include look-back to the baseline (PSI), first in-service inspection, or to the first data collected on optical disk.
3. For alloy 600 Mill-Annealed, the history review shall include look-back to the first data collected on optical disk.

Issue 2

Each utility shall review guidelines and flow charts used to provide the data analyst guidance on reporting and ensure that analysts are reporting zero percent through wall indications if they are believed to be real degradation .

The EPRI ETSS have been revised with the following note to signify when detection was outside the flaw plane:

"A value of one percent was placed in the THRUWALL column (see Data Set) when the phase of the indication reflected zero percent TW in the calibration curve, and the Peer Review Group felt that an indication was present. Zero percent TW could be misunderstood as an NDD and is not intended to reflect that condition."

Issue 3

When history review is being used to determine when additional diagnostic testing shall be performed, then the utility shall define in their site-specific data analysis guidelines what constitutes change.

This interim guidance is regarded to be effective as of the date of this letter. Additional or new requirements pertaining to the issues discussed in this letter will be considered by the NDE IRG and the IIG for implementation, as appropriate, in the next revision of the PWR SG Examination Guidelines. If you have questions, please call Mohamad Behravesh of EPRI at 650-855-2388.

Sincerely,

Lawrence F. Womack
Vice President, Nuclear Services – Diablo Canyon Power Plant
Chair, SGMP PMMP Steering Committee

cc Jim Riley – NEI
Jeff Ewin – INPO
David Steininger – EPRI
Mohamad Behravesh – EPRI

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Lawrence F. Womack
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August 18, 2003

To: Steam Generator Management Program (SGMP) Utility Steering Committees
PMMP Steering Committee
Senior Representatives
Technical Advisory Group (TAG)

From: Lawrence F. Womack
Chair, Steam Generator Management Program

Subject: Interim Guidance on Three Mile Island Tube Sever Event

Background

During the fall of 2001, eddy current inspections of steam generator (SG) tubes at Three Mile Island (TMI)-1 and Oconee Nuclear Station (ONS)-1 revealed wear scars on tubes surrounding previously plugged tubes. In both cases, it was determined that the plugged tubes had severed and impacted neighboring tubes. As a result, the NRC issued Information Notice IN2002-2, which suggested that the industry investigate the issue of plugged tubes damaging neighboring tubes on a generic basis and identify possible recommendations. EPRI contracted Framatome ANP and Westinghouse to assess the issue for once-through steam generators (OTSGs) and recirculating steam generators (RSGs), respectively (EPRI Report 1008438, dated May 2003).

Interim Guidance

Steam generator tubes removed from service by plugging are no longer inspected for degradation initiation or growth. This interim guidance letter highlights the recommendations from the generic study undertaken to identify those areas of the steam generator where propagation of degradation could lead to tube sever and thus impact neighboring in-service tubes.

Requirements

For all SG designs, utilities shall review the cross-functional effects of chemistry excursions and intrusions in addition to loose parts and foreign material on plugged tubes along with in-service tubes.

For Recirculating Steam Generators:

1. An initiative to remove from service (by deplugging or repairing) all plugs made from Alloy 600 should continue, and those that remain in service shall be inspected for cracking.
2. Unless the results of a stabilization analysis conclude otherwise, all tubes with circumferential cracks within the expansion transition region or within 0.5" of the top of tubesheet shall be stabilized. Analysis shall include the effects of the tube being locked at the first tube support plate and the potential for continued growth of degradation.

3. When plugging for AVB wear, analysis shall consider post-plugging growth to determine the need to stabilize. For tubes plugged early in life for significant AVB wear and not stabilized, an analysis shall be performed to determine if the tubes should be deplugged and stabilized, if adjacent in-service tubes should be plugged, or if bobbin coil monitoring of adjacent in-service tubes is sufficient.
4. Tubes plugged for preheater wear that have been evaluated as part of the preheater wear issue resolution do not have a potential for tube severance; however, in lieu of an analysis to determine the need for stabilization, stabilization is required.

For Once-Through Steam Generators:

1. For OEM-plugged tubes, apply stabilization criteria assuming a volumetric 100% through wall flaw in the upper span. Deplug and stabilize or stabilize and plug downstream flanking tubes as required by stabilization criteria.
2. Plugged tubes with potential for swelling, which includes tubes with repaired plugs or replaced UTS plugs, shall be deplugged, inspected, and stabilized or downstream flanking tubes shall be stabilized and plugged.
3. Tubes plugged in the lower tube end but open in the upper tube end, and tube pull locations with an open top end, require monitoring of adjacent tubes for wear in the freespan
4. Any indications of wear outside the TSPs in the freespan shall be investigated for possible tube-to-tube wear due to a severed tube.
5. If possible, stuck probe debris shall be removed at the next outage and the tube dewatered and inspected prior to replugging. Monitoring adjacent tubes for wear in the freespan is an acceptable alternative.
6. Plugged tubes in the lane region that have not been sleeved or stabilized shall be deplugged, inspected, and stabilized in the top spans or adjacent downstream and flanking tubes shall be plugged and stabilized in the top spans. This tube population in the OTSGs is also addressed by plugged tubes that have been repaired (recommendation No. 2).

This interim guidance is effective six months from the date of this letter. If a plant has a scheduled refueling outage within the six-month period, then nine months are allowed for implementation.

Sincerely,

Lawrence F. Womack
Vice President, Nuclear Services – Diablo Canyon Power Plant
Chair, SGMP PMMP Steering Committee

cc Jim Riley – NEI
Jeff Ewin – INPO
David Steininger – EPRI
Mohamad Behravesh - EPRI

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March 16, 2004

PMMP Utility Steering Committee
SGMP Senior Representatives
SGMP Technical Advisory Group (TAG)
NDE IRG
E&R IRG

Subject: Steam Generator Management Program (SGMP) Interim Guidance for EPRI Steam Generator Examination Guidelines, Revision 6, Sections 6.2.4, 6.3.3.3, 6.5 and Appendix H Supplements H1 and H2

References:

1. PG&E letter dated April 30, 2003 from Lawrence F. Womack, Chair, SGMP Senior Representatives, *Steam Generator Management Program (SGMP) Interim Guidance for Implementation of EPRI PWR Steam Generator Examination Guidelines, Revision 6*

2. PG&E letter dated September 18, 2003 from Lawrence F. Womack, Chair, SGMP Senior Representatives, *Interim Guidance for EPRI PWR Steam Generator Examination Guidelines, Revision 6, Section 6.3.3.3*

Dear Committee Members:

This letter transmits interim guidance, prepared by the NDE IRG, on the following two topics in the EPRI PWR Steam Generator Examination Guidelines, Revision 6.

<u>**Data Quality and Noise Monitoring**</u>

On January 26-27, 2004, a workshop was held to communicate the industry's fall 2003 experiences with data quality monitoring as specified in Section 6.5. Based on utility and vendor presentations, it was demonstrated that many of the data quality parameters listed in Section 6.5 could be field-implemented. However, the EPRI Tube Integrity Ad-hoc Committee is still developing the correct technique(s) to measure noise in the area of interest and the tools necessary to deal with the results from an integrity assessment perspective. At the conclusion of the workshop, the NDE IRG met to review the overall results from the industry's fall 2003 data quality verification efforts and collectively decided to reassess all parameters listed in Tables 6-2, 6-3, 6-4, and 6-5 to verify each parameter being monitored improves the accuracy of detection and sizing of tube degradation. This effort identified areas for improvements and/or deletions.

Based on the NDE IRG's comprehensive review of Section 6.5, including noise in the area of interest, additional interim guidance is warranted.

<u>**Automated Analysis Performance Demonstration Database (AAPDD)**</u>

This interim guidance is provided to incorporate increasing experience in field implementation of automated data analysis systems. This guidance was necessary due to the large number of variables associated with comparison of the automated data analysis system algorithms used in the AAPDD qualification with those used in site-specific applications. This guidance still provides the benefit of an industry qualification and the use of the AAPDD qualification algorithms to improve those used in field inspections.

<u>Interim Guidance</u>

To avoid confusion, all existing and pending interim guidance related to Revision 6 of the EPRI PWR Steam Generator Examination Guidelines have been consolidated and issued under this letter.

This interim guidance letter will address four sections (6.2.4, 6.3.3.3, 6.5, and Appendix H Supplements H1 and H2). Section 7 will not be updated by this letter, but the content of this letter is intended to supercede applicable conflicting requirements in Section 7. You should incorporate the following changes.

- Replace the information found in Section 6.2.4 with that found in Attachment 1.
- Replace the information found in Section 6.3.3.3 with that found in Attachment 2.
- Replace the information found in Section 6.5 with that found in Attachment 3.
- Add the information found in Attachment 4 as a new section H1.3.3.3 to Appendix H, Supplement H1.
- Replace the first paragraph in Appendix H, Supplement H2, Section H2.3.3 with that found in Attachment 5.

The interim guidance contained herein is effective upon receipt of this letter and shall remain in effect until superceded by another interim guidance letter or Revision 7 to the EPRI PWR Steam Generator Examination Guidelines.

Sincerely,

Lawrence F. Womack
Vice President, Nuclear Services-Diablo Canyon Power Plant
Chair, SGMP Senior Representatives

cc Jim Riley – NEI
Jeff Ewin – INPO
David Steininger – EPRI
Mohamad Behravesh – EPRI

Attachment

<u>Attachment 1</u> <u>(replaces existing section 6.2.4)</u>

6.2.4 *Site-Validated Techniques*

The purpose of the site validation of examination techniques is to ensure that the detection and sizing capabilities developed in accordance with Appendix H or J are applicable to site-specific conditions for each existing and potential damage mechanism and applicable technique.

This shall be accomplished through a documented pre-outage review of:

- All parameters on the qualified ETSS as compared to the site-specific ETSS to determine equivalency.
- Site-specific signals (for existing degradation mechanisms only) compared to ETSS signals to determine if the degradation mechanisms are characterized correctly.
- A qualified technique's tubing essential variables to ensure that the application is consistent with site-specific SG conditions. The review shall establish that tubing extraneous test variables (for example, denting, deposits, tube geometry, noise) of the tubes in the qualification data set are comparable in voltage, phase and signal characteristics to in-generator signals. The review shall determine if noise signals (for example, denting, deposits, tube geometry, system noise) in the area of interest, pose the potential for degrading the probability of detection.

The review document shall be prepared or reviewed by the utility-designated QDA and approved by the individual(s) responsible for SG tube integrity for use in the degradation assessment.

If the review determines that the technique cannot be site-validated, then one of the following actions shall be taken:

- Explore other techniques.
- Develop or augment ETSS with representative data (for example, pulled tubes, lab samples).
- Go to Section 6.2.5.

Attachment 2 (replaces existing section 6.3.3.3)

6.3.3.3 *Automated Data Analysis*

Automated analysis of eddy current data is achieved by systems incorporating software that allows the transformation of eddy current data into an analyzed output.

These systems are typically applied in one of the following ways:

- Detection only mode: The software detects signals and the analyst applies manual analysis to the signal to decide whether to accept or reject the signal.
- Interactive mode: The software detects and analyzes the signals and the analyst reviews the signals identified by the software and compares them with his/her own analysis of the signals before the results are accepted or rejected.
- Fully automated mode: The software detects and analyzes the signals and the analysis results are accepted with no human intervention.

Automated analysis systems shall be qualified through performance demonstration as follows:

- The initial generic performance capability (qualification) of an automated analysis system shall be demonstrated and documented in accordance with all of the practical examination requirements found in Appendix G.4.2 (with the exception that the false call requirements may be relaxed at the utility's discretion). This initial qualification is performed on the applicable Automated Analysis Performance Demonstration Database (AAPDD) which validates detection and sizing/characterization algorithms for each applicable known damage mechanism found in Table G-1. Different algorithms may be required based on variations in AAPDD essential variables (for example, instrument types, drive voltages, tubing sizes, coil excitation frequencies).
- It is recommended to use the initial generic performance algorithms as a source of information for help in establishing the site specific algorithms.
- The site-specific performance capability of an automated analysis system shall be demonstrated and documented in accordance with Section 6.3.2.

Attachment 2 continuation of section 6.3.3.3

Qualification shall be demonstrated independent of human intervention. *Human intervention* is defined as an analyst operating the automated analysis system deleting, adding, or changing a result. In addition, each analyst operating an automated analysis system shall meet the qualification requirements without the automated analysis system as described in this document.

Application of automated analysis systems shall be limited to the mode that was qualified. Those automated analysis systems qualified for the detection-only mode are limited to detection-only. The qualified interactive mode is the combination of the qualified system and the qualified analyst. Those automated analysis systems qualified for the interactive mode or fully automated mode are not limited in their application.

Key points to be observed in the use of dual automated analysis systems are the following:

- Both teams may use automated analysis systems for detection provided they are independent systems. However, if the detection algorithms are the same, they are not considered independent; and at least one team shall analyze all data manually to ensure the detection algorithms are not missing degradation.
- Both teams may use automated analysis systems for sizing/characterization provided they are independent systems. However, at least one of the two analysis teams or the resolution team shall review all the analysis results manually to verify the sizing/characterization algorithm.

Attachment 3 (replaces existing section 6.5)

6.5 *Data Quality Requirements*

The purpose of this section is to provide data quality requirements for SG eddy current examinations. Implementing the following requirements is expected to improve accuracy in detecting and sizing tube degradation. In addition, implementation of these requirements is expected to identify retests during the acquisition process rather than the analysis process thus improving the overall examination process.

Data quality parameters are divided into four tables and are separated as generic (Table 6-2), bobbin (Table 6-3), rotating plus point or rotating pancake (Table 6-4), and array probes (Table 6-5). The tables provide a frequency, location, acceptance criteria, and corrective action for each of the listed quality parameters.

Table 6-2
Generic Data Quality Parameters

Quality Parameter	Frequency	Location	Acceptance Criteria	Corrective Actions
Summary verification	Once per calibration and at every summary	Summary file	Correct site, unit, SG, owner, identification, model, calibration standard(s), probe(s) type, manufacturer, length and serial number, motor unit length and serial number, cable length and type, procedure with revision level, instrument serial number, examination technique specification sheet number with revision number, software version with revision level, operator with certification level, frequencies, mode of operation, date, scan direction, data collected from inlet/outlet or other parameters essential to the documentation associated with this calibration set.	Correct information, retest tubes with correct summary, or document errors through a corrective action program.
Tube identification number	Each tube	Tube	The data file present reflects the correct tube identification with independent verification by an additional method.	Retest tube with correct tube identification.
Extent tested	Each tube	Tube	Planned beginning to planned end for each portion of tube or entire tube.	Retest all or portion of tube to complete test.
Presence of an initial calibration standard data file (R999-C999)	Once per calibration group	Data file	Data file present at beginning of calibration group. Calibration standard encoded properly.	Reject data, retest calibration standard, correct data file, or document error in a message.
Saturation	Continuous	Area of interest	The eddy current signal(s) of channel(s) required by the site ETSS are within the dynamic range of the instrument.	Reject data or document evaluation.
Presence of eddy current signals	Continuous	Area of interest	Frequencies required by the site ETSS to be monitored are functional.	Reject data.
Drive voltage	Once per data file	Data file	Setting equal to site ETSS.	Reject data.
Gain setting	Once per data file	Data file	Setting equal to site ETSS.	Reject data.

Attachment 3 continuation of section 6.5

Table 6-3
Bobbin Data Quality Parameters

Quality Parameter	Frequency	Location	Acceptance Criteria	Corrective Actions
Measurement on reference defects	Once at end of calibration group	Calibration standard	Phase changes on normalized reference signal (Section 6.2.7.5) ±5°. Amplitude changes on normalized reference signal (Section 6.2.7.5) ±20%. (If there is no end calibration due to equipment failure, no check is required)	Reject data or document evaluation of alternate acceptance criteria.
Sampling rate	Continuous	Structure-to-structure	≥ to site ETSS.	Reject data if < site ETSS.
Presence of parasitic noise	Continuous	Area of interest	≤1 spike per 12 in. (304.8 mm) and on <2 frequencies required by the site ETSS for detection and/or detection and sizing. A spike is defined as signal less than 5 data points in duration with an included angle less than 5° and an amplitude >1volt.	Reject data or document evaluation of alternate acceptance criteria.

Attachment 3 continuation of section 6.5

Table 6-4
Rotating Plus Point or Rotating Pancake Data Quality Parameters

Quality Parameter	Frequency	Location	Acceptance Criteria	Corrective Actions
Circumferential encoding signal (trigger pulse for the motor unit)	Continuous	Area of interest	Data terrain plots correctly.	Reject data or document evaluation of alternate acceptance criteria.
Measurement on reference defects	Once at end of calibration group	Calibration standard	Phase changes on normalized reference signal (Section 6.2.7.5) ±5°. Amplitude changes on normalized reference signal (Section 6.2.7.5) ±20%. (If there is no end calibration due to equipment failure, no check is required)	Reject data or document evaluation of alternate acceptance criteria.
Axial sampling rate	Continuous	Area of interest	≥ to site ETSS.	Reject data if < site ETSS.
Presence of parasitic noise	Continuous	Area of interest	≤1 spike per 10 consecutive revolutions on <2 frequencies required by the site ETSS for detection and/or detection and sizing. A spike is defined as signal less than 5 data points in duration with an included angle less than 5° and an amplitude >1 volt.	Reject data or document evaluation of alternate acceptance criteria.
Circumferential sample rate	Continuous	Area of interest	≥ site ETSS.	Reject data if < site ETSS.

Attachment 3 continuation of section 6.5

Table 6-5
Array Probe Data Quality Parameters

Quality Parameter	Frequency	Location	Acceptance Criteria	Corrective Actions
Presence of all channels in the array	Continuous	Area of interest	The presence of all channels in the array.	Reject data or document evaluation of alternate acceptance criteria.
Measurement on reference defects	Once at end of calibration group	Calibration standard	Phase changes on normalized reference signal (Section 6.2.7.5) ±5°. Amplitude changes on normalized reference signal (Section 6.2.7.5) ±20%. (If there is no end calibration due to equipment failure, no check is required)	Reject data or document evaluation of alternate acceptance criteria.
Coil response and centering	Once per calibration	Calibration standard	Amplitude ≤20% difference between maximum and minimum response to an OD groove.	Reject data or document evaluation of alternate acceptance criteria.
Channel ordering	Once per calibration	Calibration standard	Array channel representation in the correct circumferential and axial positions.	Reject data.
Sampling rate	Continuous	Structure-to-structure	≥ to site ETSS.	Reject data if < site ETSS.
Presence of parasitic noise	Continuous	Area of interest	≤1 spike per 12 in. (304.8 mm) and on <2 frequencies required by the site ETSS for detection and/or detection and sizing. A spike is defined as signal less than 5 data points in duration with an included angle less than 5° and an amplitude >1 volt.	Reject data or document evaluation of alternate acceptance criteria.

Attachment 3 continuation of section 6.5

The data quality parameters provided in this section shall be verified by manual, semi-automated, or automated methods. Prior to using an automated method, it is recommended that a thorough functionality check be performed and documented that validates the process is performing as desired. During the development of these tables, information was gathered to develop acceptance criteria. While some of these data quality monitoring parameters may prove to be too restrictive, the basis for reduction of frequency or less stringent criteria shall be documented.

6.5.1 Probe Quality Parameters

Probe manufacturing tolerances can have a profound effect on data quality. Continuous monitoring of probe manufacturing tolerances during data acquisition would not be practical. Therefore, utilities shall request probe manufacturers to verify the applicable critical probe manufacturing parameters that can affect data quality and require the manufacturer to provide a certificate of conformance to the applicable portion of Table 6-6.

Table 6-6
Probe Manufacturing Quality Parameters

Quality Parameter	Coil Type(s)	Acceptance Criteria
Center frequency	All coils	The center frequency is within 10% of design.
Dissymmetry	Differential coils	Within ±10% amplitude difference between the average of the two lobes of the 100% TW hole.
Coil winding alignment	Rotating and array	≤10% secondary lobe on a 100% axial notch.
Coil winding perpendicularity	Plus point coils	160°–200° between 100% axial and 100% circumferential notches.
Probe coil circumferential position	Multiple coil, solid body probes	≤10° between nominal and measured circumferential position.
Probe flux	Bobbin (non-external reference)	Main lobe ≥90% of total amplitude.
Probe coil axial position	Multiple coil, solid body probes	≤0.1 in. (2.54 mm) between nominal and measured axial position.
360° coil coverage	Array coils	Polar plot with measurements taken at ≤ 1° increments around the tube on a 100% TW hole having a diameter equal to or less than ½ the diameter of the coil but not less than 1/16 inch. Acceptance being a minimum response (crossover point between adjacent coils) ≥ 80% of the normalized maximum response of all sensing coils.

Attachment 4 (new section to be added after page H-17)

H1.3.3.3 Array Probe

The following essential variable definitions apply for array probes .

H1.3.3.3.1 Phase to Depth Curve

See Section H1.3.3.1.6

H1.3.3.3.2 Diametral Coil Offset

The diametral offset is the maximum possible distance between the outer surface of a coil in an array probe and the inner surface of the tube being inspected. The Diametral Coil Offset is defined as the maximum difference between the ID of the tube and the outer surface of the coil presuming the probe body is at an extreme off-center position. See Figure H1-2.

Diametral Offset (inches) = Tube ID – Probe Body OD + Coil Recess

The diametral offset value may be reduced through the use of probe centering devices.

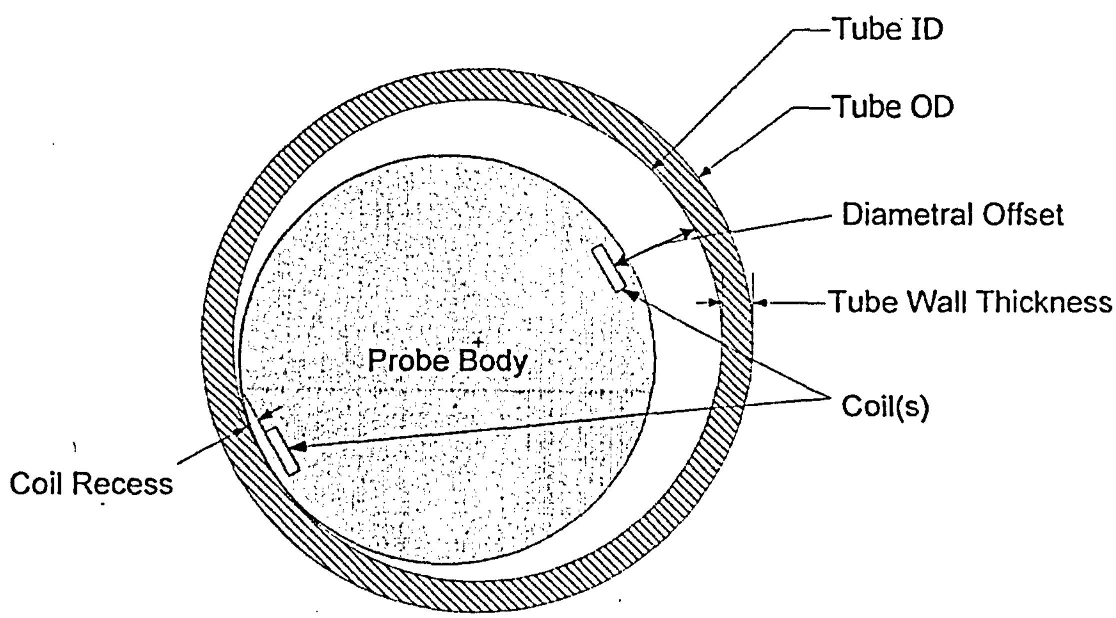

Figure H1-2

H1.3.3.3.3 Coil Density

Coil density is the number of coils around the circumference of the probe as compared to the inside diameter of the tube to be inspected. This definition can be used provided the coils are of the same type and size (transmit/receive spacing if applicable) as previously qualified.
Coil Density (coils per inch) = Number of Coils / Tube ID Circumference

H1.3.3.3.4 Effective Circumferential Field Width

Effective circumferential field width is the circumferential extent in degrees between the ½ amplitude points of an individual coil as determined in the normalized polar plot. When evaluating this measurement consider compensating for diameter. The effect of the hole is normalized. This definition can be applied if the coil sizes between array probes are not equal.

H1.3.3.3.5 Depth Coefficient

See Section H1.3.3.1.3

H1.3.3.3.6 360° Coil Coverage

Polar plot as defined in Table 6-6.

Attachment 5 (replaces first paragraph in section H2.3.3)

Appendix H, Supplement H2,
Section H2.3.3

Replace the first paragraph with the following:

"*Noise$_{ET}$* next to the area of interest shall be measured and recorded on the examination technique specification sheet. These measurements are performed in the freespan regions of interest (sludge pile, expanded tube sections, non-expanded tube sections and bent tube sections) excluding end effects, expansion transitions, tube support signals, bars, straps, bend transitions and flaws. Where practical (appropriate data exists), each applicable freespan region of interest will have three measurement increments above and below the flaw. Mixing of measurements between freespan regions of interest is prohibited. These values will be averaged for each flaw location. The measurements are performed as follows:"

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May 11, 2004

Steam Generator Management Program (SGMP) Utility Steering Committee
PMMP Steering Committee
Senior Representatives
Technical Advisory Group (TAG)

Subject: Interim Guidance on EPRI Steam Generator In Situ Pressure Test Guidelines, Revision 2, Chapter 10

Background

This interim guidance is provided to correct typographical errors identified recently in Chapter 10 of the EPRI Steam Generator In Situ Pressure Test Guidelines. Specifically, the typographical errors are in Table 10-1, Section 10.5 and Section 10.6.

This chapter was significantly revised during the last revision of the guidelines. Chapter 10 contains guidance in leak rate adjustments and Table 10 contains material property corrections for testing at room temperature to main steam line break conditions. Section 10.5 provides the basis for the leak rate adjustments, and Section 10.6 provides example calculations.

Interim Guidance

Enclosed is a revised Chapter 10. The changes are as follows:

Table 10-1, ¾" Thermally Treated 0.043" Westinghouse, at 650 degrees MSLB Temperature, the correction factor is changed from 1.0896 to 1.139.

Chapter 10.5.4 and Chapter 10.6, Subscripts T and R were changed to C and H.

Effective immediately, please replace Chapter 10 in Revision 2 of the EPRI Steam Generator In Situ Pressure Test Guidelines with the enclosed Chapter 10. This interim guidance will be superseded by the next revision of the guidelines.

Sincerely,

Lawrence F. Womack
Vice President, Nuclear Services – Diablo Canyon Power Plant
Chair, SGMP Senior Representatives

Cc: Jim Riley – NEI
Jeff Ewin – INPO
David Steininger – EPRI
Mohamad Behravesh – EPRI

Enclosure

10. IN SITU PRESSURE TESTING AND LEAK RATE ADJUSTMENTS

10.1 Introduction

In situ pressure tests are typically conducted at room temperature. Therefore adjustments are required to simulate both normal and accident conditions. Consequently, an engineering assessment shall be performed and maintained, or cited by reference, as part of the test record that demonstrates that the test is capable of producing the stress state at the flawed section of tubing which is equivalent to, or a conservative bound, of the actual stress state during normal operation and postulated accident conditions, multiplied by the appropriate factor of safety. The purpose of this Chapter is to provide information regarding the assessments required to simulate the effects of induced axial loads during accident events, the impact of temperature on material properties and the differences in thermal hydraulic conditions for leak rates at accident conditions (phase change and flashing) versus test conditions.

10.2 Induced Axial Loads

In situ pressure and leak rate tests for circumferentially oriented flaws shall consider the presence of axial loads during faulted MSLB event scenarios. These axial loads may result from either locked tubes in support plates for RSG designs, or from adverse tube-to-shell thermal differences in an OTSG. Locked tube adjustment factors to be applied to in situ test pressures are tooling and generator design specific and shall be coordinated with information from the original NSSS supplier and the in situ testing vendor. When evaluating the locked tube corrections, the tool design and operational characteristics, as well as the steam generator design and geometry can affect the correction to be applied. The user should verify with the in situ vendor that the corrections are adequately modeled. The applied end cap load should equal the end cap load developed by the limiting loading condition or the leak test condition times the applicable cross sectional area of the tube.

Different lengths of tubing between locking points and differences in material properties will impact the correction factor. For example, in [24], for CE plant tubing, using a localized tool which can generate axial forces, it is shown that a correction factor of 1.09 is bounding for a 47 inch span, while for the 27 inch span the correction factor increases to 1.13. A factor of 1.15 is expected to be generally bounding. Conversely, for a full tube pressure test with locking at the first support, the required correction factor is 1.78.

Section 9 contains information to support the evaluation of in situ tooling capable of simulating axial loading for proof testing. For leak rate adjustments, the evaluator should consider the effect of the axial load on the crack opening area when developing thermal hydraulic conversion factors.

10.3 Temperature Adjustment

To extrapolate proof test results from ambient *in situ* test conditions to service conditions, a correction for temperature effects on the flow stress of the tubing is required. From the EPRI Flaw Handbook [4] it can be noted that the dimensionless (normalized) burst pressure equation can be written in general form as:

$$P_N = \frac{1}{2}\frac{P_B}{\sigma_f}\frac{R_m}{t} = f(\textit{flaw geometry}) \qquad \text{Eq. (10-1)}$$

where:

P_B	=	burst pressure	[psi]
R_m	=	tube mean radius	[in]
σ_f	=	flow stress	[psi]
t	=	tube wall thickness	[in]

Both the tube and flaw geometries are considered to be the same for both the hot and cold conditions, which means that if the dimensionless burst pressure is to be the same under both hot and cold conditions, then

$$P_{BC} = \frac{\sigma_{fC}}{\sigma_{fH}} P_{BH} \qquad \text{Eq. (10-2)}$$

where the subscripts C and H refer to the cold and hot conditions respectively.

Consequently, the hot pressure differential of interest must be multiplied by the ratio σ_{fC}/σ_{fH}, to determine the equivalent cold test pressure. Table 10-1 provides this correction factor for several types of tubing. The flow stress values have been obtained from [4].

Table 10-1
Material Property Corrections for Testing at Room Temperature to MSLB Conditions

Tube Description	MSLB Temperature	σ_{fc}/σ_{fl}
3/4" Mill Annealed 0.043" Westinghouse	650	1.079
3/4" Mill Annealed 0.048" ABB	620	1.078
3/4" Mill Annealed 0.042" ABB	620	1.076
3/4" Thermally Treated 0.043" Westinghouse	650	1.139
7/8" Mill Annealed 0.050" Westinghouse	650	1.097
7/8 Thermally Treated 0.050 Westinghouse	650	1.139
11/16" Mill Annealed 0.040" Westinghouse	650	1.091
11/16" Thermally Treated 0.040" Westinghouse	650	1.139
5/8" Stress-relieved OTSG Tubing (0.034" min. wall)	605	1.091

10.4 Adjustments of In situ Measured Leak Rates

In situ leak testing is normally performed at room temperature (~70°F) and the results are applied to one or more accident condition pressure differentials. Therefore, in situ leak rates must be corrected to accident conditions for comparison to the specified limits. The calculated accident induced leak rate should be compared to the performance criteria of NEI 97-06 [1].

The extrapolation of room temperature test results to actual conditions of interest requires an understanding of the applicable phenomena and their governing parameters. For leakage these are the crack opening area, and the thermal hydraulic conditions for the flow. The importance of this conversion is highlighted in NRC Information Notice 97-79 [7].

The general approach for scaling is to use available mathematical models to extrapolate results from known conditions to other ones of interest. By having experimental data at one particular condition, it is possible to make the mathematical model fit the data exactly at that point. The model can then be used to extrapolate for particular parameters while others remain constant. The approach that is followed here is to ratio the applicable equations at the conditions of interest (hot), with the measured conditions (cold). This approach allows a determination of the appropriate adjustment factors for the quantities of interest.

The adjustment is performed as shown here, with the details provided in the next section. First the cold temperature test pressure is determined by Equation 10-2 or Table 10-1. The leakage mass flow ratio is:

$$\frac{M_H}{M_C} = \frac{A_H}{A_C}\frac{G_H}{G_C}$$ Eq. (10-3)

where:

M	=	mass flow rate	[lb/s]
A	=	crack opening area	[in^2]
G	=	mass flux	[lb/s in^2]

And the subscripts C and H refer to cold and hot conditions respectively.

The crack opening area ratio, when the pressure ratio is chosen according to Eqn. 10-2 is:

$$\frac{A_H}{A_C} = \frac{\sigma_{fH}}{\sigma_{fC}}\frac{E_C}{E_H}$$ Eq. (10-4)

where:

σ_f	=	flow stress	[psi]
E	=	Young's Modulus	[psi]

For the case where $A_H/A_C \sim 1$, the mass flux ratio becomes:

$$\frac{G_H}{G_C} = \left\{\frac{[P_{0H} - P_S(T_{0H})]}{[P_{0C} - P_S(T_{0C})]}\frac{\rho_s(T_{0H})}{\rho_s(T_{0C})}\right\}^{\frac{1}{2}}$$ Eq. (10-5)

where:

G	=	mass flux	[lbs/s in^2]
$P_S(T_0)$	=	saturation pressure at temperature (T_0)	[lbs/in^2]
P_0	=	pipe internal pressure	[psi]
ρ	=	density	[lbs/in^3]
$\rho_s(T_0)$	=	saturated liquid density at temperature (T_0)	[lbs/in^3]
T_0	=	internal fluid temperature	[°F]

The volumetric leakage flow, Q, can be obtained from the mass flow rate by dividing by the appropriate density.

$Q = M/\rho$ Eq. (10-6)

For the volumetric leakage flow at room temperature conditions, the density at room temperature is used. For the accident conditions the hot density is used.

10.5 Basis for the Leakage Rate Adjustments

Several experimental results and calculation methods appear in the literature for flow through cracks under conditions of high pressure [20], [21], [22]. The motivation generally has been to provide the ability to predict primary to secondary leakage flow in steam generators.

Most of the calculation methods are fairly simplistic, and are amenable to hand calculations, though a computer code, PICEP [8], has been developed to utilize more detailed elastic/plastic pipe deformation and two phase fluid flow models.

The experimental database used to validate the available models is sparse, and is heavily weighted to relatively large cracks. In addition, most of the data has been obtained for machined slits, for which the geometries are much easier to characterize than for real cracks. In spite of this the available data for small cracks has a great deal of scatter.

A crack leakage calculation consists of two steps. First a crack opening area is determined, which is then used with a thermal hydraulic model to calculate the flow.

The mass flow rate through the crack is given by,

$$M = AG \qquad \text{Eq. (10-7)}$$

Where:

M	=	mass flow rate	[lbs/s]
A	=	crack opening area	[in^2]
G	=	mass flux	[lb/s in^2]

First, the crack opening area, A, as a function of pressure, needs to be determined. This can be accomplished in a straightforward manner by using the EPRI Ductile Fracture Handbook [6] or the Steam Generator Tubing Burst Testing and Leak Rate Testing Guidelines [3].

The next sections describe the determination of the crack opening area for both axial and circumferential cracks.

10.5.1 Axial Cracks

The geometry and nomenclature for a single axial crack is provided in Figure 10-1.

The dimensionless crack half length, λ, is given by

$$\lambda = \frac{c}{\sqrt{Rt}} \qquad \text{Eq. (10-8)}$$

where:

c	=	crack half-length	[in]
R	=	tube mean radius	[in]
t	=	tube wall thickness	[in]

For a tube under internal pressure the effective dimensionless crack half length is:

$$\lambda_e = \frac{c_e}{\sqrt{Rt}} \qquad \text{Eq. (10-9)}$$

which can be determined [6] by solving:

$$\frac{c_e}{c} = \frac{\lambda_e}{\lambda} = 1 + \frac{F_m^2(\lambda_e)}{2}\left(\frac{\sigma}{\sigma_f}\right)^2 \qquad \text{Eq. (10-10)}$$

where:

σ	=	hoop stress	[lb/in^2]
σ_f	=	flow stress	[lb/in^2]

and the shell bulging factor, F_m, is defined as:

$$F_m(\lambda) = 1 + 0.072449\lambda + 0.648567\lambda^2 - 0.2327\lambda^3 + 0.038154\lambda^4 - 0.0023487\lambda^5. \qquad \text{Eq. (10-11)}$$

Since,

$$\sigma = \frac{(P_0 - P_2)R}{t} \qquad \text{Eq. (10-12)}$$

where:

P_0	=	internal pressure	[lb/in^2]
P_2	=	external pressure	[lb/in^2]

The effective crack length, c_e, can be obtained for any particular pressure difference by iteration of equation 10-10, starting with the initial estimate of:

$F_m(\lambda_e) = F_m(\lambda)$.

Once the effective crack length has been determined, the crack opening area is given by

$$A = 2\pi c_e^2 V_o \sigma / E \qquad \text{Eq. (10-13)}$$

where:

$$V_o = 1.0 + 0.64935\,\lambda_e^2 - 8.9683\text{x}10^{-3}\,\lambda_e^4 + 1.33873\text{x}10^{-4}\lambda_e^6 \qquad \text{Eq. (10-14)}$$

and

E = Young's Modulus [lb/in^2].

10.5.2 Circumferential Crack

The geometry for a single circumferential crack is given in Figure 10-2.

The crack half angle θ is used to define λ

$$\lambda = \theta\,(R/t)^{0.5} \qquad \text{Eq. (10-15)}$$

The effective crack half angle, adjusted for plastic zone size, can be determined [6] by solving:

$$\frac{\theta_e}{\theta} = \frac{\lambda_e}{\lambda} = \left[1 + \frac{F_m^2(\lambda_e)}{2}\left(\frac{\sigma}{\sigma_y}\right)^2\right] \qquad \text{Eq. (10-16)}$$

where:

σ_y = Material Yield stress

$F_m(\lambda) = 1 + 0.1501\lambda^{3/2}$ for $0 \le \lambda \le 2$ Eq. (10-17a)

or

$F_m(\lambda) = 0.8875 + 02625\lambda$ for $2 \le \lambda \le 5$ Eq. (10-17b)

The calculation is again an iterative one, where λ and F_m are updated using a new θ_e in place of θ, (Eqns. 10-15, 10-17) and the updated F_m is used to calculate a new θ_e from Eqn. 10-16.

The equation for the crack opening area is given in [6] as,

$$A = 2\pi Rt \times B_7 \times \frac{\sigma}{E}$$ Eq. (10-18)

where:

$\sigma = P_0R/2t$ Eq. (10-19)

$B_7 = \lambda^2 + 0.16\lambda^4$ for $0 \le \lambda \le 1$ Eq. (10-20a)
$B_7 = 0.02 + 0.81\lambda^2 + 0.30\lambda^3 + 0.03\lambda^4$ for $1 \le \lambda \le 5$ Eq. (10-20b)

10.5.3 Flow rate

Most crack flow models, for a subcooled inlet flow, are of the following general form:

$$G = \sqrt{\frac{2g\rho(P_0 - P_2)}{(1+\xi)}}.$$ Eq. (10-21)

For the current calculations we use the form suggested by Pana, as described in [20],

$$G = \sqrt{\frac{2g\rho_S(T_0)[P_0 - P_S(T_0)]}{(1+\xi)}}$$ Eq. (10-22)

where:

G	=	mass flux	[lb/hr in^2]
g	=	gravitational constant	[in/s^2]
P_2	=	tube external pressure	[lb/in^2]
$P_S(T_0)$	=	saturation pressure at temperature T_0	[lb/in^2]
ρ	=	density	[lb/in^3]
$\rho_s(To)$	=	saturated liquid density at temperature T_0	[lb/in^3]
T_0	=	internal fluid temperature	[°F]
ξ	=	overall friction coefficient	[dimensionless]

The overall friction coefficient is given by:

$$\xi = 0.5 + \frac{t}{d_H}\left(3.39\log\frac{d_H}{R_f} - 0.866\right)^{-2}$$ Eq. (10-23)

where:

t	=	wall thickness	[in]
d_H	=	hydraulic diameter of the crack	[in]
R_f	=	crack wall surface roughness	[in]

The wall surface roughness is a difficult parameter to determine. Most experiments have been performed in the range of 1×10^{-5} to 1.5×10^{-3} in. A convenient value that has commonly used [3] is 2×10^{-4} in.

10.5.4 Scaling Analysis

For leakage scaling analysis we take the ratio of the hot scaled mass flow over the cold test mass flow. The subscripts C and H refer to the cold test and hot reference conditions respectively.

$$\frac{M_H}{M_C} = \frac{A_H}{A_C}\frac{G_H}{G_C} \qquad \text{Eq. (10-24)}$$

and using Eqn. 10-13 for axial cracks

$$\frac{A_H}{A_C} = \left(\frac{c_{eH}}{c_{eC}}\right)^2 \frac{V_{0H}}{V_{0C}}\frac{\sigma_H}{\sigma_C}\frac{E_C}{E_H} \qquad \text{Eq. (10-25)}$$

and Eqn. 10-18 for circumferential cracks

$$\frac{A_H}{A_C} = \frac{B_{7H}}{B_{7C}}\frac{\sigma_H}{\sigma_C}\frac{E_C}{E_H} \qquad \text{Eq. (10-26)}$$

and Eqn. 10-22

$$\frac{G_H}{G_C} = \left\{\frac{[P_{0H} - P_S(T_{0H})]}{[P_{0C} - P_S(T_{0C})]}\frac{\rho_s(T_{0H})}{\rho_s(T_{0C})}\frac{[1+\xi_H]}{[1+\xi_C]}\right\}^{\frac{1}{2}} \qquad \text{Eq. (10-27)}$$

If temperatures and pressures can be specified for both the test and reference conditions, it is possible to determine the relative mass flow rates, M_H/M_C.

When tests are performed on a model system rather than on the real one, it is desirable that the model system response be as close to the prototypic one as possible. For a cracked tube at cold temperature to represent one at hot temperature a good choice would be to have the effective length of the cracks to be the same for both the cold and the hot conditions. From Eqn. 10-2, it can be seen that this could be accomplished by running the test in such a manner that the ratio of the tube stress to the flow stress is the same for both the model and the prototype. This means that

$$\frac{\sigma_C}{\sigma_{fC}} = \frac{\sigma_H}{\sigma_{fH}}$$ Eq. (10-28)

which results in the following choice for the test pressure given by

$$\frac{P_C}{P_H} = \frac{\sigma_{fC}}{\sigma_{fH}}$$ Eq. (10-29)

For this choice:

$\lambda_{eC} = \lambda_{eH}$

$c_{eC} = c_{eH}$

and therefore

$V_{0C} = V_{0H}$

and therefore, 10-25 reduces to:

$$\frac{A_H}{A_C} = \frac{\sigma_{yH}}{\sigma_{yC}} \frac{E_C}{E_H}$$ Eq. (10-30)

This means that the crack area ratio depends only upon the properties of the tube material at the two temperatures. If the area ratio is close to one, the overall friction coefficients will also be close, and the mass flux scaling factor will depend only on the thermodynamic conditions. This means that the crack flow scaling factors will be independent of the crack geometry.

For circumferential cracks the choice of pressure ratio given by 10-29 yields:

$\theta_{eH} = \theta_{eC}$

and consequently

$B_{7H} = B_{7C}$

Therefore, the crack opening area ratio becomes:

$$\frac{A_H}{A_C} = \frac{\sigma_{yH}}{\sigma_{yC}} \frac{E_C}{E_H}$$

which is identical to that for axial cracks, and is seen to be independent of the crack geometry. The crack leakage scaling factor can be obtained from Eqns. 10-24, 10-27, and 10-30.

10.6 Example Calculation

Let us look at the case where a test is run at room temperature to simulate MSLB conditions. For this situation, $P_{0H} = 2500$ lbs/in^2, $T_{0H} = 620$°F, and $T_{0C} = 70$°F.
For ¾" Mill Annealed 0.048" ABB Alloy 600 tubing Table 10-1 gives

$\sigma_{fC}/\sigma_{fH} = 1.078$

From [23],

$E_{70} = 31.0 \times 10^6$ psi

$E_{620} = 28.6 \times 10^6$ psi

Using Eqn. 10-2,

$$\frac{P_{0C}}{P_{0H}} = 1.078$$

and the required testing pressure at room temperature is

$P_{0C} = 2695$ lb/in^2

Using Eqn. 10-4, the area ratio is simply

$$\frac{A_H}{A_C} = \frac{1}{1.078} \times \frac{31.0}{28.6} = 1.0054$$

which is very close to one. Since for this case the flow areas are almost equal, the friction factors are essentially the same and, Eqn 10-5 becomes:

$$\frac{G_H}{G_C} = \left\{ \frac{[P_{0H} - P_S(T_{0H})]}{[P_{0C} - P_S(T_{0C})]} \frac{\rho_s(T_{0H})}{\rho_s(T_{0C})} \right\}^{\frac{1}{2}}$$

$$\frac{G_H}{G_C} = \left\{ \frac{[2500 - 1787]}{[2695 - 0.4]} \frac{40.55}{62.50} \right\}^{\frac{1}{2}} = 0.414$$

and finally using Eqn 10-3 we get

$$\frac{M_H}{M_C} = 0.416$$

Therefore the leakage mass flow rate measured in the room temperature test needs to be multiplied by 0.416 to obtain the MSLB leakage mass flow rate.

The volumetric flow rate, Q, is just given by

$$Q = \frac{M_H}{\rho}$$

where ρ is the density for the conditions where the volumetric flow is desired.

To obtain the volumetric flow rate under the MSLB conditions the density at 620°F and 2500 psi (40.55 lb/ft^3) needs to be used.

To obtain the room temperature and pressure volumetric flow rate for MSLB, the density at 70°F and 14.7 psia (62.50 lb/ft^3) needs to be used.

To convert the volumetric flow result from the room temperature test to the room temperature volumetric flow for the MSLB condition, the measured volumetric flow is just multiplied by 0.416.

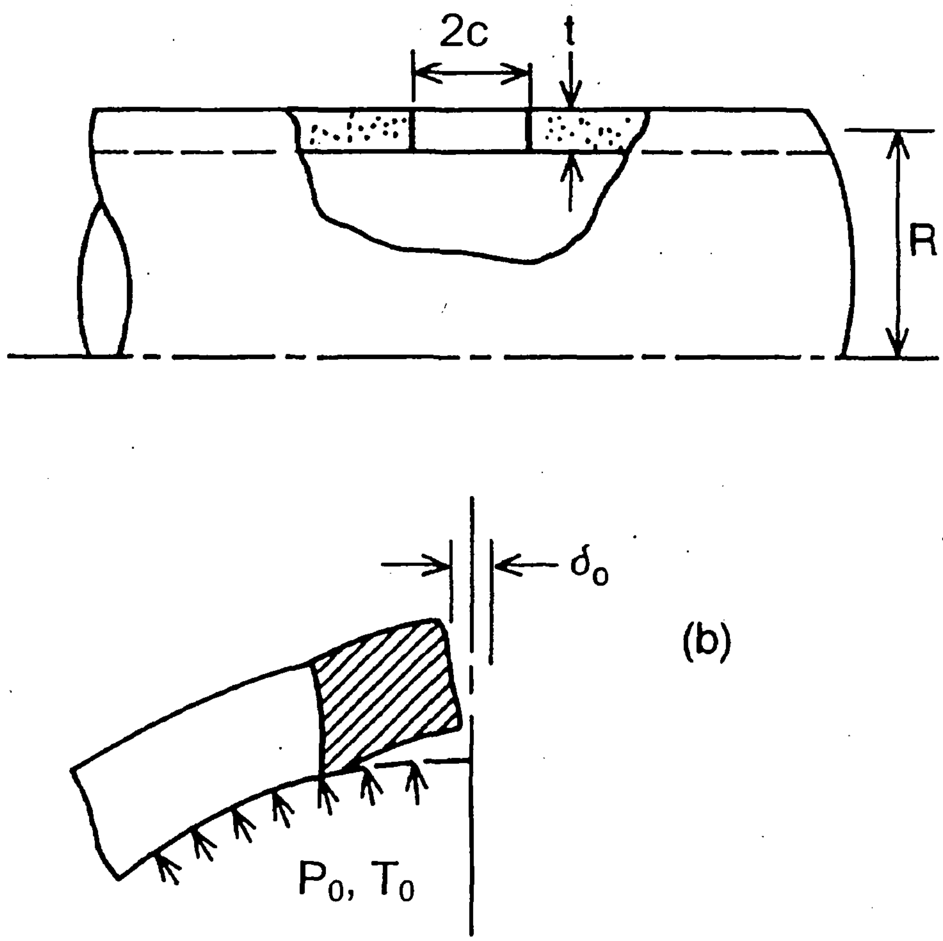

Figure 10-1. Pipe Axial Crack Geometry

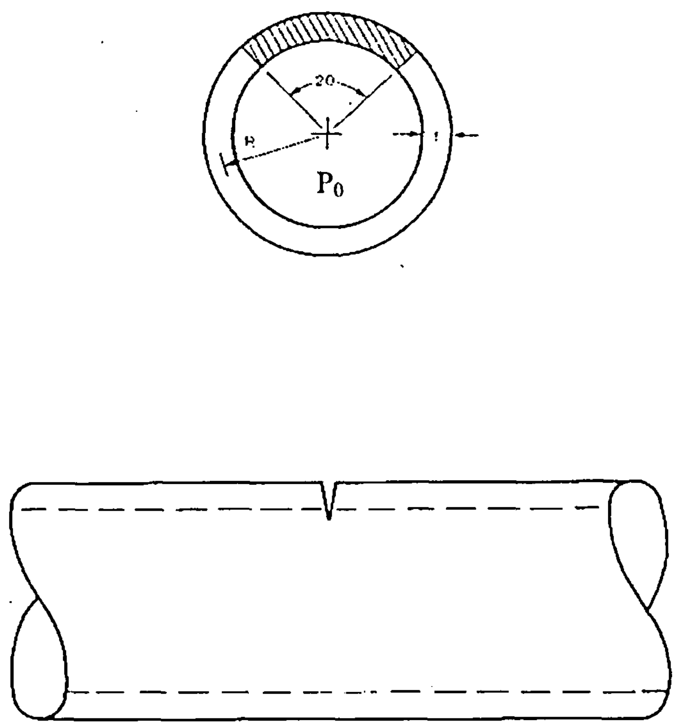

Figure 10-2. Pipe Circumferential Crack Geometry

ELECTRIFY THE WORLD

EPRI

Date: January 17, 2005

To: SGMP Technical Advisory Group
PMMP Executive Committee
SGMP IIG
SGMP E&R IRG
SGMP NDE IRG

Subject: SGMP-IG-05-01, *Interim Guidance on Revised Structural Integrity Performance Criterion (SIPC)*

References:

1. Steam Generator Integrity Assessment Guidelines, Rev.1, EPRI TR-107621-R1, March 2000
2. Impacts of the Structural Integrity Performance Criterion on Steam Generator Tube Integrity Evaluations, EPRI 1009541, December 2004.
3. NEI 97-06, Revision 1, January 2001
4. Presentations to the Structural Integrity Performance Criteria Implementation Workshop, December 9-10, 2004 , San Francisco, posted on the epriq.com

Purpose

The purpose of this interim guidance is to communicate the completion and approval of the revised SIPC and impact studies and to provide guidance for their implementation. This interim guidance has been approved by the SGMP IIG and PMMP Executive Committee and is effective as of the date of this letter. The revised SIPC is provided as Attachment 1 and will be effective until included in the next revisions of NEI 97-06 and the Integrity Assessment Guidelines.

Background

The SGMP has completed an industry study to review the impact of the revised SIPC for steam generator tubing as defined for the industry in the new Generic License Change Package (GLCP). The overall objective of the revised SIPC is to clarify the intent of the existing criterion and to document further the technical basis for its provisions. As part of this review, comments received from the industry as well as from the NRC staff were addressed. Subsequent to several technical meetings between industry representatives and NRC staff, the revised SIPC was finalized and has been included in TSTF 449 Revision 2, which was submitted to the NRC on October 7, 2004.

This interim guidance is provided to assist utilities in implementing the revised SIPC and to outline actions that are required by utilities to verify that their steam generator program meets the requirements of the revised SIPC.

The revised SIPC does not add new requirements to the intent of the existing SIPC for determining structural limits for steam generator tubes. It may require additional calculations or documentation to demonstrate continued application of existing structural limits, for example those in existing draft Regulatory Guide 1.121 analyses. The revised SIPC formalizes the details needed in evaluating design basis accident loads and their consideration in establishing structural limits for tube degradation. In particular, the revised SIPC includes details for treating significant non-pressure accident loads and specific safety factors to be applied to contributing accident loads. Since these details have not been delineated in past guidelines, it is necessary for utilities to verify compliance with present requirements.

Elements in the Revised SIPC

The revised SIPC identifies three separate analyses: Evaluate structural integrity with a safety factor of 3.0 against normal operating pressure differential (NODP), with a safety factor of 1.4 against the limiting accident pressure differential (LAPD), and for accident loading combinations with a safety factor of 1.2 for pressure loads and concurrent primary loads other than pressure that contribute significantly to burst and a safety factor of 1.0 for axial secondary loads. The structural limit that is most limiting shall govern.

1. The safety factor of 3.0 against burst under normal steady state full power primary-to-secondary differential pressure is to ensure that the overall tube integrity is maintained for all normal operating and upset conditions and can be verified through condition monitoring. **The revised performance criterion makes no changes to this part of the definition.**

2. The safety factor of 1.4 against burst from differential pressure is associated with the largest or limiting accident differential pressure for Service Level C (emergency) and D (faulted) events. **NOTE:** Historically, Level D (faulted) conditions have been used for evaluation of limiting design basis accidents by regulatory precedence. Service Level C events have been explicitly included in the SIPC in order to address all accidents for the plant design. However, postulated Level D accident events generally impose the most limiting conditions for primary-to-secondary differential tube pressures and therefore should be bounding for the design basis accidents, including Level C events. Each plant shall determine the limiting accident differential pressure. **It is expected that level D conditions will bound Level C conditions; however verification of this is necessary.**

3. **In addition to stresses induced by differential pressure during design basis accidents, the tubes may be subjected to other primary loads, and to axial thermal loads from differential temperatures created during transients.** Consequently, the SIPC includes provision for an assessment of loading conditions defined in the design

and license basis that could potentially contribute to reducing the tube burst pressure. The inclusion of these loads, when determined to significantly affect tube burst conditions, shall have a safety factor of 1.2 applied to the combined primary load sources, and a safety factor of 1.0 applied to the axial secondary loads. The significance of potentially contributing loads on tube burst has been established by testing. Based on the test results, these potential contributing loads do not affect the burst pressure of axial cracks. These test results and details on how to determine plant-specific loads are included in EPRI Report No. 1009541 (Reference 2). This report includes, as appendices, the technical reports produced by the project contractors.

Tube collapse by net section plastic failure under combined tension and bending loads is also to be evaluated to the SIPC. The criterion applies to tube failure from plastic collapse due to the formation of plastic hinges and is not related to collapse from external pressure (implosion). Based on results from plastic collapse testing of flawed and unflawed tubing for both straight and U-bend geometries, it has been demonstrated by tests that plastic collapse is not a relevant failure mode for steam generator tubing. For straight sections of tubing, substantial bending loads cause locking in tube support structures that restricts further tube end rotation and axial displacements. This effectively delays plastic collapse in bending to much higher loads. Plastic collapse of U-bends under in-plane bending leads to very large displacements. Such large displacements are restricted by interference with neighboring tubes. Therefore, tube burst is the failure mode of concern for steam generator tube integrity for normal and accident loading conditions. **No further action is required for the assessment of collapse.**

<u>Effects on In Situ Pressure Test Guidelines</u>

The in situ pressure test requirements contained in the EPRI In Situ Pressure Test Guidelines are not affected by the revised SIPC when 3.0 NODP or 1.4 LAPD is limiting. When the structural limit for tube integrity is imposed by the requirement for combined accident loads, an equivalent pressure can be established for in situ pressure test considerations.

<u>Interim Guidance</u>

Each plant shall evaluate structural limits to ensure they meet the revised SIPC. Unless degradation is covered by one of the following screening criteria, structural limits shall include contributing loads according to the revised SIPC.

Since postulated Level C accident events have been assumed to be bound by Level D events in determining the most limiting conditions for LAPD, each plant shall validate that this is the case for their plant conditions.

The SIPC impact study concluded that the structural limits for the following damage mechanisms are not impacted by loads other than pressure

- Axial degradation anywhere in the bundle for any SG design
- Circumferential degradation in CE designed square bend SGs
- Circumferential degradation less than 270 degrees, in recirculating SGs in straight sections below the top tube support plate

- Circumferential degradation in the U-bend flank region
- Circumferential degradation in recirculating SG less than 25 PDA
- Flat bar wear in recirculating SGs

Alternatively, the results of the SIPC impact study can be used in lieu of a plant-specific analysis if it can be shown that specific plant conditions used in the impact study bound plant-specific conditions. Each plant shall document the evaluation in appropriate plant documents. For example, it is likely that structural limits for circumferential degradation less than 270 degrees, in recirculating SGs in low row U-bends (ratio of bend radius to mean tube radius less than 52.5) will not be impacted by non-pressure loads. However, specific plant conditions were used to come to this conclusion. It is necessary to ensure that the analyzed conditions bound your plant's conditions prior to concluding that the results of this analysis are applicable to your SGs

The most likely scenario is that the conditions (e.g., damage mechanism, location) affected by the described changes will not impact current structural limits for degradation present in licensee's steam generators and thus will not affect current operational assessments. However, if it is determined that current operational assessments are affected, the information shall be entered into the plant's corrective action program and the operational assessment revised.

<u>Discussion of Screening Criteria and Requirements</u>

It has been established through testing that there is no impact of the revised SIPC with the evaluation of structural limits for axial degradation. Structural limits for circumferential degradation in once-through steam generators and in the U-bend areas of recirculating steam generators may be affected by the revision of the SIPC.

SGs originally designed by Combustion Engineering with "square" bends have been demonstrated to not require additional consideration with regard to bending loads. The tubes with square bends are supported vertically and horizontally at relatively short spans and therefore are restrained from significant motion in any direction. The examples in Section 4.2 of the Appendix C of the SIPC report (Reference 2) show that the applied bending moment does not affect the structural limit of these tubes. The low row tubes (e.g., first 18 rows) in these steam generators have U-bends. Low row U-bends have been shown by the AREVA tests to respond to bending moments essentially the same as supported straight tubes. Therefore the analysis for the supported square bend tubes also applies to the low row U-bends. The conclusion is that the value of the structural limit for circumferential degradation in CE designed SGs is not reduced by non-pressure induced loads.

The term circumferential degradation refers to any type of degradation with significant circumferential extent. This includes volumetric degradation such as wear and volumetric IGA. Volumetric degradation can be evaluated by considering the circumferential and axial lengths. If the circumferential length controls the burst pressure, it should be considered as circumferential degradation. Under axial and bending loads, the depth and circumferential extent of these types of degradation lead to a fracture and burst behavior similar to circumferential cracking and should be evaluated accordingly. Axial loads can contribute to burst at all locations within the bend. Bending loads can contribute to burst for circumferential degradation at the intrados and

extrados of the bend but will not contribute to burst for degradation away from these locations. Therefore, structural limits for circumferential degradation limited to the tube flank regions will not be affected by primary bending loads. The tube flank is defined as the lines that are 90 degrees from the intrados and extrados of the U-bend and extending 45° to either side of these lines.

Circumferential degradation less than 25 percent degraded area is not affected by bending loads. This is based on the fact that the burst pressure of a tube with a PDA of 25 or less is the undegraded tube burst pressure even for the worst case morphology. At a PDA of 25, the EPRI Flaw Handbook burst pressure calculation already incorporates a conservatism equivalent to the effect of an outer fiber bending stress of about 50,000 psi in a large radius U-bend, which has been assumed in the impact study to be a bounding outer fiber bending stress.

The guidance in the reference reports provides an analysis method based on test data for computing burst pressure reductions due to bending loads. This method covers all forms of circumferential degradation including part through wall degradation when the circumferential extent of degradation is not excessively large. When the extent of degradation approaches the full tube circumference of the tube, the developed burst model may be non-conservative. Therefore, when PDA is greater than 25 and the circumferential extent exceeds the allowable through-wall length for burst, it is recommended that the PDA be represented as a uniformly deep, 360° crack and the burst pressure computed based on the fully-plastic net-section failure load for combined tension and bending acting on a free standing tube. This method is discussed in Section 7.4 of Appendix B of the report (Reference 2). This alternate analysis covers the bounding case of axisymmetric degradation around the entire tube circumference.

Presentation material at the Structural Integrity Performance Criteria Implementation Workshop included an example that provides conclusions that flat bar wear is not impacted by bending loads. This example used parameters specific to recirculating SGs, therefore, it should not be extended to once through SGs without further evaluation.

For plants with once through steam generators, axial thermal loads will be controlling for circumferential degradation. Therefore, it is necessary to perform an assessment to determine the appropriate factor of safety to use for the axial thermal loads (1.2 or 1.0). If 1.0 is deemed appropriate, the existing integrity evaluations shall remain valid since they are based on elastic calculations. If it is necessary to apply a safety factor of 1.2, additional analysis/assessment must be performed. In this case, advantage can be taken of plasticity effects and load reductions due to decreased stiffness caused by the presence of degradation. A BWOG sponsored testing/analysis project is underway to quantify plasticity and decreased stiffness effects on load reduction at constant imposed displacement.

Time to Implement the Interim Guidance

For plants not experiencing or predicting circumferential degradation, an evaluation of structural limits to assess the effects of loads in addition to pressure that have been concluded to contribute to burst of tubes with circumferential degradation is not necessary until such time that circumferential degradation is predicted.

For plants with CE SGs with square bends, an evaluation of structural limits to assess the effects of loads in addition to pressure that have been concluded to contribute to burst of tubes with circumferential degradation is not necessary.

For plants with recirculating steam generators that are not experiencing circumferential degradation in the U-bend intrados or extrados area but predicting this degradation in the Degradation Assessment, structural limits can be set to 25 percent degraded area (PDA) and the evaluation of contributing loads can be performed in the future.

For plants with recirculating steam generators with circumferential degradation in the U-bend intrados or extrados area, this documentation shall be done as soon as it is expected that circumferential degradation will be identified that is greater than 25 percent degraded area (considering NDE uncertainties). It is likely that the plant will not have loading information available to them and it will be necessary to contact the original equipment manufacturer to obtain this information. Once the applicable loading information is obtained, Reference 2 contains guidance for determining the significance of the loads and Reference 4 provides examples.

For once-through SGs, structural limits may be impacted by this change and will need the information from the BWOG testing to complete the evaluation. If this is the case, the plant should enter this condition into their corrective action program.

Sincerely,

Jeffrey T. Gasser

Jeffrey T. Gasser
Executive Vice President and Chief Nuclear Officer, Southern Nuclear
Chair, PMMP Executive Committee

cc: Jim Riley – NEI
Jeff Ewin – INPO
David Steininger – EPRI
Mohamad Behravesh – EPRI

Attachment 1

Replacement for Existing Structural Performance Criteria (SIPC)
Steam Generator Integrity Assessment Guidelines: Revision 1 Section 5.1

Structural and repair limits are defined for each degradation mechanism based upon satisfying the structural integrity performance criterion, which is stated below.

The revised structural integrity performance criterion is:

> *All inservice steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cooldown and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.*

Changes in design parameters such as plugging or sleeving levels, primary or secondary modifications, or T_{hot} should be assessed. Such changes shall be included if they result in a primary to secondary pressure difference that is greater than the value in the design or equipment specification by more than 50 psi.

This chapter presents requirements, for establishing the structural and repair limits associated with steam generator tubing, which satisfy the performance criterion. Determination of these limits requires that an acceptable structural parameter, such as wall thickness or crack length, be identified that can be related to the structural integrity of the tubing, and can be adequately measured by qualified NDE technology. This process must review the practicality of the selected NDE technique for the chosen structural parameter.

NEI 97-06 R2 Section	NEI 97-06 Change from Revision 1	Document Affected	Interim Guidance
3.1	Degradation Assessments: EPRI *Steam Generator Integrity Assessment Guidelines* [6] and EPRI *PWR Steam Generator Examination Guidelines* [2] provide guidance for Degradation Assessments.	IA G/L, Exam G/L	While not as complete as the next revision will be, Chapter 3 of the Integrity Assessment Guidelines, Revision 1 provides guidance for performing Degradation Assessments. Revision 6 of the Examination Guidelines provides additional guidance. **No interim guidance is necessary.**
3.3	Integrity Assessment: "The EPRI *Steam Generator Integrity Assessment Guidelines* [6] shall be used to determine the evaluation methods, margins, and uncertainty considerations used to evaluate tube integrity. "	IA GL	Revision 1 of the Integrity Assessment Guidelines, Chapters 8 and 9 provide guidance on methods and uncertainty considerations. The safety margins and performance criteria have been revised by TSTF 449 and NEI 97-06 Rev. 2. **Interim Guidance: The new performance criteria in NEI 97-06 Rev. 2 shall apply to future assessments. Also refer to January 17, 2005 Interim Guidance Letter from EPRI SGMP**
3.3	Integrity Assessment: The EPRI *Steam Generator In Situ Pressure Test Guidelines* [7] shall be used for guidance on screening criteria for candidate tube selection, as well as for test methods and testing parameters.	In Situ G/L	The In Situ Pressure Test Guidelines, Revision 2 provide guidance on screening criteria for candidate tube selection as well as for test methods and testing parameters. **No Interim Guidance is necessary.**

NEI 97-06 R2 Section	NEI 97-06 Change from Revision 1	Document Affected	Interim Guidance
3.3	Integrity Assessment: The EPRI *Steam Generator Tubing Burst Testing and Leak Rate Testing Guidelines* [17] provide further guidance for pulled tube examinations.	SG Tube Burst Test and LR Test GL	The Burst Testing and Leak Rate Testing Guidelines provide guidance for pulled tube examinations. No interim guidance is necessary
3.3	Integrity Assessment: Section 3.1.3 in rev 1 used to require that licensees complete an OA within 90 days of startup. This was removed from 97-06 with the intention of including the requirement in the IA G/L. In general, the old section 3.1.3 was reduced with the intention of adding the details that were removed to the IA guideline.	IA G/L	NEI 97-06, Revision 2 deletes the requirement for completing an operational assessment within 90 days after startup. **Interim Guidance: Until the next revision of the Integrity Guidelines is implemented, plants shall complete an operational assessment for the next operating period within 90 days after startup. If completion of this assessment is not possible due to the complexity of the analysis within the 90-day period, a preliminary assessment is acceptable as an interim measure.**
3.4	Tube Plugging and Repairs Additionally, licensees shall perform a pre-service inspection of the plugging or repair consistent with the latest revision of the EPRI *PWR Steam Generator Examination Guidelines*	Exam GL	Section 3 of the Examination Guidelines, Revision 6, provides guidance for preservice of plugging and repairs. **No interim guidance is necessary.**
3.4	Tube Plugging and Repairs The EPRI *PWR Steam Generator Tube Plug Assessment Document* [8] and the EPRI *PWR Sleeving Assessment Document* [9] provide further guidance for maintenance and repair of tubing.	Tube Plug Assess and Sleeving Assessment docs	The Tube Plug Assessment and Sleeving Assessment documents provide guidance. **No interim guidance is necessary.**

NEI 97-06 R2 Section	NEI 97-06 Change from Revision 1	Document Affected	Interim Guidance
3.6	Secondary side integrity: Provide additional guidance on maintenance of SG secondary side integrity in the IA G/L	IA G/L	NEI 97-06, Revision 2 discusses maintenance of SG secondary-side integrity and states that additional guidance is provided in the Integrity Guidelines. Chapter 1.5 of the Integrity Guidelines, Revision 1 states that integrity assessments include, *"all steam generator components which are part of the primary pressure boundary (e.g., tubing, tube plugs, sleeves and other repairs). It also includes loose parts and secondary side structural supports (e.g., tube support plates) that may, if severely degraded in some manner, compromise pressure retaining components of the steam generator."* Chapter 3.3 states, *"To provide appropriate outage planning, approximately three months prior to an anticipated refueling outage in which steam generators will be inspected, previously identified and potential degradation forms on both the secondary and primary sides of the*

NEI 97-06 R2 Section	NEI 97-06 Change from Revision 1	Document Affected	Interim Guidance
			steam generator that affect tubing, support structures, pressure and leak boundaries should be identified as to location and possible extent." Revision 2 of the Integrity Assessment Guidelines will provide additional guidance; however, until this revision is published, the Examination Guidelines provide a list of considerations while performing assessment on the secondary side. INPO letter dated May 24, 2005 provides additional suggestions for inclusion into these assessments. **No interim guidance is necessary at this time.**

NEI 97-06 R2 Section	NEI 97-06 Change from Revision 1	Document Affected	Interim Guidance
3.9.1	Loose parts and foreign objects: "A record of these evaluations (secondary side inspections) shall be maintained in accordance with the provisions in the *PWR Steam Generator Examination Guidelines [2].*" ... "Additional guidance on secondary side inspections is provided in the *PWR Steam Generator Examination Guidelines [2].*" In general, during the development of the GLCP we promised the NRC that we would enhance our guidance on inspecting for loose parts. These were seen as the potential downfall of extended inspection intervals.	Exam G/L	NEI 97-06, Revision 2 states that foreign objects left in the SG should be evaluated to show that they will not cause unacceptable tube damage and that the evaluation shall be maintained in accordance with the SG Examination Guidelines. Evaluations of objects left in the SG are not currently addressed in Revision 6 of the SG Examination Guidelines. In addition, it is likely that the Integrity Guidelines will include this information. **Interim guidance: The licensee shall maintain documentation of evaluations performed to justify leaving foreign objects in the steam generator during the subsequent operating cycle(s).**

NEI 97-06 R2 Section	NEI 97-06 Change from Revision 1	Document Affected	Interim Guidance
3.10	Contractor oversight: "Additional guidance on contractor oversight can be found in the EPRI steam generator guidelines that govern the activity."	IA G/L, Exam G/L, In Situ G/L	NEI 97-06, Revision 2 discusses contractor oversight and states that additional guidance on contractor oversight can be found in the EPRI SG guidelines that govern the activity. The SG Examination Guidelines include additional guidance. Integrity Guidelines Revision 2 will provide this guidance. **Interim Guidance: In general, the utility engineer is responsible for integrity assessments. While this work may be contracted out, the utility engineer shall be knowledgeable enough to ensure that inputs and conclusions are correct.**
3.12.2.2	External reporting requirements: "Detailed reporting requirements [to the SGMP] are contained in the governing EPRI SGMP guidelines."	<u>All</u> SG G/L are affected	There is no list of reporting requirements detailed in Integrity Guidelines, Revision 1; however, reporting requirements that are not contained in NEI 97-06 and are required by the Integrity Guidelines are contained within its Chapters (i.e., DA, CM, OA). Revision 2 will have a more complete listing of all external reporting requirements. **No interim guidance is necessary at this time.**

NEI 97-06 R2 Section	NEI 97-06 Change from Revision 1	Document Affected	Interim Guidance
App B	Definitions: A number of definitions were developed or changed during the development of the GLCP, namely: Collapse, Normal Steady State Full Power Operation, Primary Stress, Repair Methods, Secondary Stress, and Significant Loads. These need to be incorporated into the appropriate guidelines.	IA G/L	These definitions will be included in the Integrity Assessment Guidelines. **Interim Guidance: The definitions in NEI 97-06 and TSTF 449 shall be used for future assessments.**

ELECTRIC POWER RESEARCH INSTITUTE

Date: October 10, 2005

To: SGMP Technical Advisory Group
PMMP Executive Committee

Subject: SGMP-IG-05-02, NEI 97-06 Revision 2, "Steam Generator Program Guidelines"

References:

1. Steam Generator Integrity Assessment Guidelines, Revision 1, EPRI TR-107621-R1, March 2000
2. Pressurized Water Reactor Steam Generator Examination Guidelines, Revision 6, EPRI 1003138, October 2002
3. NEI 97-06, Steam Generator Program Guidelines, Revision 1, January 2001
4. TSTF-449, Rev. 4, Technical Specification Task Force, Improved Standard Technical Specifications Change Traveler, Steam Generator Tube Integrity
5. NEI Letter dated September 2, 2005

Purpose

The purpose of this interim guidance is to communicate the issuance of NEI 97-06, Revision 2 and some identified gaps between this revision and current EPRI guidelines.

Background

Many plants are submitting requests for licensing amendments to adopt the Generic Licensing Change Package (GLCP) and are receiving approval for the new regulatory framework. Revision 2 of NEI 97-06 was issued on September 2nd 2005, to align the industry initiative with the GLCP. The EPRI SGMP currently has two important guidelines under revision that will also incorporate key aspects of the GLCP and provide guidance referenced by NEI 97-06, Revision 2.

The timing of the guideline revision publications will be several months after NEI 97-06 Revision 2 issuance. The attached table identifies areas in NEI 97-06, Revision 2 that reference EPRI guidelines for further guidance. An analysis was performed to identify gaps between NEI 97-06 Revision 2 and the EPRI PWR Steam Generator Examination Guidelines, Revision 6 and the Integrity Assessment Guidelines, Revision 1. Where gaps were identified, interim guidance has been provided in the comments section of the table. This table is similar to the table distributed with NEI 97-06, Revision 2. The

NEI table identified the gaps, the table attached to this guidance identifies interim guidance to address the gaps until the appropriate guideline revisions are published.

Interim Guidance

Between the time of NEI 97-06, Revision 2 implementation and the implementation of EPRI PWR Steam Generator Examination Guidelines, Revision 7 and Integrity Assessment Guidelines, Revision 2, the guidance identified on the table shall be incorporated into utilities' Steam Generator Program.

NEI 97-06, Revision 2 includes a requirement that every licensee change its technical specifications consistent with NEI 97-06 and its associated regulatory framework in TSTF-449. The intent of this requirement is that plants revise their technical specifications. The timing of the technical specification submittal should be determined by each utility. The CLIIP process is available through May 6, 2006. It is not the intent for the technical specification revision to be submitted by the 6 month implementation deadline specified in Reference 5.

Implementation Date

Implementation of this interim guidance is not immediate, but **shall** be implemented along with the implementation of NEI 97-06, Revision 2 (Reference 5) and will be in effect until Revision 7 of the EPRI PWR Examination Guidelines and Revision 2 of the EPRI Steam Generator Integrity Assessment Guidelines are published.

Sincerely,

Jeffrey T. Gasser

Jeffrey T. Gasser
Executive Vice President and Chief Nuclear Officer, Southern Nuclear
Chair, PMMP Executive Committee

cc: SGMP IIG
SGMP E&R IRG
SGMP NDE IRG
Jim Riley, NEI
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ELECTRIC POWER RESEARCH INSTITUTE

Date: October 18, 2005

To: SGMP Technical Advisory Group
PMMP Executive Committee

Subject: SGMP-IG-05-03, *Interim Guidance on Identification of "Mandatory", "Shall" and "Recommended" Elements for Revision 5 of the EPRI PWR Primary Water Chemistry Guidelines (1002884)*

References:

1. NEI 97-06 (Rev 2), Steam Generator Program Guidelines, NEI, Washington, DC: 2005
2. NEI 03-08, Guideline for the Management of Materials Issues, NEI, Washington, DC: May 2003.
3. *Steam Generator Management Program Administrative Procedures, Revision 1,* EPRI, Palo Alto, CA: 2004. 1011274

Background

The US nuclear power industry established a framework for increasing the reliability of steam generators by adopting NEI 97-06, *Steam Generator Program Guidelines* (Reference 1). This initiative references EPRI's Water Chemistry Guidelines, including the *EPRI PWR Primary Water Chemistry Guidelines*, as the basis for an industry consensus approach to chemistry programs. Specifically, the initiative requires that US utilities meet the intent of the *EPRI PWR Primary Water Chemistry Guidelines.* The focus of the NEI initiative is steam generator integrity. These *Guidelines* are a support document under NEI 97-06. These *Guidelines* include control parameters and monitoring requirements which must be incorporated into a plant's water chemistry program in order to meet the intent of these *Guidelines.*

The U.S. nuclear industry has more recently produced a policy that commits each nuclear utility to adopt the responsibilities and processes on the management of materials aging issues described in NEI 03-08, *Guideline for the Management of Materials Issues* (Reference 2).

The Steam Generator Management Program (SGMP) Administrative Procedures (Reference 3) provides guidance that is to be followed by guideline revision committees with regard to specifying which portions of guidelines are "mandatory" or "shall" requirements, and which portions are "recommendations" in accordance with NEI 03-08. These categories are described as follows:

(1) Guideline elements designated as "mandatory" are important to steam generator tube integrity and should not be deviated from by any utility. Steam Generator tube integrity means meeting the performance criteria.

(2) Guideline elements designated as "shall" are important to long-term steam generator reliability but could be subject to legitimate deviations due to plant differences and special situations.

(3) Guideline elements designated as "recommendations" are good or best practices that utilities should try to implement when practical.

Interim Guidance

In accordance with NEI 97-06, NEI 03-08 and the SGMP Administrative Procedure, the *PWR Primary Water Chemistry Guidelines Revision 5 (1002884)* have been reviewed by an industry Review Committee to identify the "mandatory", "shall" requirements, and "recommendation" portions as follows:

- The only "mandatory" requirement is that utilities must have a Strategic Primary Water Chemistry Plan in accordance with Chapter 4 of Volume 1 of these *Guidelines*. This plan shall be a living document which is approved by utility management.
- All Action Level 1, 2, and 3 responses in Chapter 3 of Volume 1 of these *Guidelines* are "shall" requirements.
- The only "shall" requirements of Table 3-1 of Volume 1 are that pH_{Tave} shall be ≥ 6.9 and $pH_{Tave} = 7.4$ shall be considered an upper bound to the pH_{Tave} target.
- All of the control parameters, including all associated action level values, hold values, monitoring frequencies, and footnotes, in Tables 3-3, 3-6 and 3-7 in Chapter 3 of Volume 1 of these *Guidelines* are "shall" requirements. With respect to footnotes (5) and (11) of Table 3-3 of Volume 1, the only relevant aspects of Table 3-1 to the "shall" requirement are that pH_{Tave} shall be ≥ 6.9 and $pH_{Tave} = 7.4$ shall be considered an upper bound to the pH_{Tave} target.
- All other guideline elements are recommended for consideration, including Appendix B of Volume 1 and all of Volume 2, but the extent of use is at the discretion of the individual plant/utility. However, any exception to any of the diagnostic parameters in Chapter 3 of Volume 1 should be documented in the Strategic Water Chemistry Plan.

Deviations to "mandatory" and "shall" requirements shall be handled in accordance with the guidance in the current revision of the Steam Generator Management Program (SGMP) Administrative Procedures. A temporary non-compliance to a "shall" monitoring requirement, such as a temporary inability to take continuous samples, does not need to be treated as a

deviation per the SGMP Administrative Procedures. Rather, the reasons for the temporary non-compliance, together with the compensatory actions taken, should be documented in the plant records.

Time to Implement the Interim Guidance

This interim guidance has been approved by the SGMP Executive Committee in accordance with the SGMP Administrative Procedures, Rev. 1. Licensees shall implement this interim guidance within six months of this letter's issuance. If the next refueling outage is less than six months away, the licensee may delay the use of this interim guidance for an additional three months.

Sincerely,

Jeffrey T. Gasser
Executive Vice President and Chief Nuclear Officer, Southern Nuclear
Chair, PMMP Executive Committee

cc: Jim Riley – NEI
Jeff Ewin – INPO
David Steininger – EPRI
Mohamad Behravesh – EPRI
SGMP IIG
SGMP TSS
Chemistry Committee
LLW Committee
RM TAC

10

MAINTENANCE OF SG SECONDARY SIDE INTEGRITY

10.1 Introduction

The SG program shall include measures to maintain the SG secondary-side integrity as required by NEI 97-06. Monitoring and projecting secondary side steam generator conditions for the purpose of developing a strategy for long-term steam generator operability and performance shall be part of the utility's steam generator program. This strategy will assist in developing inspection intervals, anticipating future maintenance activities, and planning for contingencies. A secondary side integrity plan requires analysis and trending of chemistry, operational parameters, and inspection data (See Figure 10-1). Examples of potential inputs into the secondary side integrity plan may include, but are not limited to the following:

1. Steam Generator Design
    a. Materials of Construction
    b. General Design and Configuration
    c. Thermal Hydraulic Information (High Flow Regions, etc)

2. Secondary Side Chemistry History/Trends
    a. SG Chemistry Excursions (Operating and Shutdown)
    b. Scale and Deposit Removal/Chemical/Profiling Analysis
    c. Corrosion Product Transport and Mass Balance
    d. Hideout Return

3. Secondary Side Maintenance History/Trends
    a. Tubesheet Sludge Deposit Removal
    b. Tube Support Plate / Upperbundle Fouling
    c. Foreign Objects
        i. Foreign Objects Identified, Removed, and Remaining in the SGs
        ii. Foreign Objects Identified that Caused Tube Wear

4. Site Specific and Industry Operating Experience (OE)
    a. FME or Equipment Degradation Events (SG Foreign Objects Concern)
    b. NDE Detectability Issues (Foreign Objects Detection)
    c. Secondary Side Visual Inspection Results
    d. Secondary Side Component Integrity (Including GL 97-06)

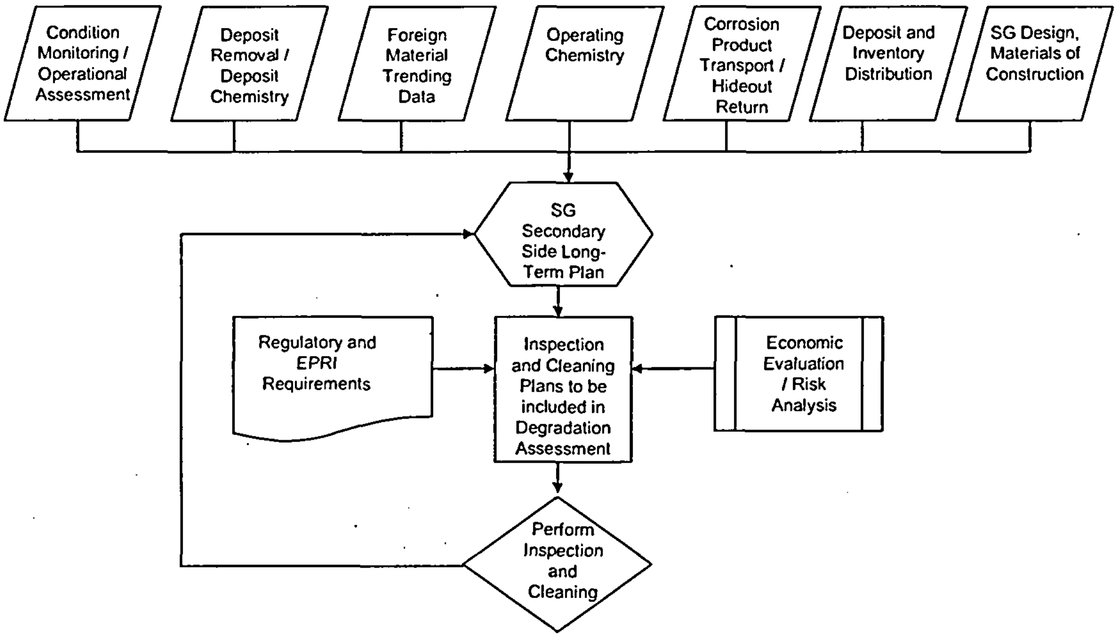

Figure 10.1 Process of Recording, Monitoring, and Assessing Data

10.2 Purpose

The overall purpose of the secondary side integrity plan is to provide the SG Engineer with a long-term planning tool for refueling outage scope. This plan maintains an assessment of the current status of the secondary side of the SGs, forecasts future SG performance characteristics and inspection and cleaning plans, and recommends and prioritizes appropriate corrective actions as necessary to support changing conditions. This is especially important with SGs with more advanced tubing material where primary and secondary side inspections may be skipped. Regulatory and EPRI requirements, economics, and risks shall all be considered and communicated to appropriate levels of management.

10.3 Secondary Side Assessments

The plant's Degradation Assessment, Condition Monitoring, and Operational Assessments shall include assessments of secondary side conditions.

Degradation Assessments shall include the secondary side integrity plan, which can be directly incorporated into the Degradation Assessment or as a reference in the Degradation Assessment. Outage planning that does not include secondary side activities, such as sludge lancing or FOSAR, shall be documented with critical thinking supporting the plan. Contingency planning shall consider events outside the SG Engineer's control such as exceeding water chemistry guideline limits over an extended period of time or frequently, or known foreign material identified in the feed train. The secondary side integrity plan shall include consideration of operating experience (OE) from all PWRs, not just sister plants' OE.

Condition Monitoring shall include aspects of the secondary side inspection that affect tube integrity such as secondary side inspections performed, foreign material removed, and foreign

material remaining in the steam generators. This information may be included in the Condition Monitoring assessment directly, or with a reference to associated engineering analysis.

Operational Assessments shall include a justification for operating the planned interval between secondary side inspections as well as primary side inspections.

10.4 Secondary Side Cleaning

Steam generator cleaning strategies are either preventive or reactive. Controlling steam generator sludge deposit accumulation through sludge lancing every outage supplemented by more aggressive cleaning methodologies at appropriate intervals is a preventive approach. This approach will prevent potential operational issues that have been associated with sludge accumulation such as tubing corrosion, heat transfer limitation, and water level instability. Since the secondary side will be opened for maintenance activities, FOSAR shall also be performed. This approach has the least risk.

The reactive approach includes plans for outages where no sludge lancing or FOSAR is performed with aggressive cleaning plans for future outages to restore the steam generator when the long-term plan indicates operational issues associated with sludge accumulation have the potential to occur. It is essential that steam generator conditions are well understood prior to implementing a reactive approach. The risks with this approach include financial risks associated with a larger number of more aggressive cleaning campaigns and risks with inaccuracies in predicting the onset of operational issues. The other risk involved with this strategy is the potential that foreign objects would remain inside the SGs for a longer period of time.

The secondary side integrity plan considers the risks and benefits of both strategies and recommends an approach for the utility. While both Alloy 600 and 690 thermally treated tubes are more resistant to alkaline stress corrosion cracking than mill annealed Alloy 600 tubes, consideration shall be given to their potential corrosive attack over time. Both thermally treated and mill annealed Alloy 600 tubing are susceptible to acid attack. As sludge and scale deposits form regions where corrosive impurities can concentrate, care must be taken to minimize their buildup on and around tube surfaces. Due to the different corrosion susceptibilities of the different tubing materials, the more resistant tubing can tolerate sludge deposition to a greater degree. These differences shall be considered in formulation of the appropriate cleaning strategy.

Some of the more aggressive cleaning techniques include high pressure tubesheet sludge lancing, ultrasonic energy cleaning, tube bundle flush, scale conditioning agents, and chemical cleaning. Many plants have incorporated sludge collectors in their replacement SG designs to minimize sludge accumulation at the top of the tubesheet.

10.5 Secondary Side Visual Inspections

Foreign object search and retrieval inspections shall be performed at a minimum each time the secondary side at the top of tube sheet of the steam generator is opened for maintenance access

(for example, sludge lancing) for recirculating steam generators. Because of the design of once through steam generators, foreign object intrusion is not expected; therefore, FOSAR shall be performed when loose parts are identified or there is reason to expect that they were introduced into the steam generator secondary side. Secondary side visual examinations shall be performed to assist in the verification of tube integrity. The personnel performing secondary side visual inspections and FOSAR activities shall be trained in use of the equipment and procedures utilized. This training shall include FME control.

Secondary side visual inspections shall also consider utility commitments in accordance with NRC GL 97-06, such as visual inspections to detect potential degradation to the wrapper and tube support plates to ensure tube structural integrity is maintained.

A detailed evaluation shall be performed to document the maximum interval between secondary side inspections. This evaluation shall be based on historical foreign objects, wear indications, similar plant inspection results, maintenance activities, and the planned eddy current inspection intervals. The evaluation shall contain the following elements:

- Location and description of historical foreign objects,
- Description of those foreign objects with associated wear indications
- Failure of control and monitoring of foreign objects
- High flow, or susceptible areas
- Inspection limitations
- Categorization of probable causes, origins, and migration
- Trends for foreign objects associated wear, and
- Eddy current detectability issues

When scheduling sludge lancing and FOSAR, the following should be considered:

- Sludge lancing tends to sweep material that is in-bundle toward the annulus for easier retrieval, therefore, performing sludge lancing before FOSAR tends to optimize FOSAR attempts. Retrieval is also easier with the sludge pile removed.

- However, wear associated with foreign material may be easier to disposition if the object remains unmoved by lancing.

Several plants have experienced problems with foreign objects after a steam generator replacement, therefore, a FOSAR should be performed during the outage when replacement SGs are installed. The SGs are typically kept on their sides for several years and when they are in place, material and debris could fall to the tubesheet and become accessible. In addition, many replacement steam generators have incorporated foreign object strainers, typically as part of the feed ring design, to minimize foreign objects from entering the SG tube bundle region during operation. These strainers should be routinely inspected and considered in the secondary side integrity plan.

Depending on the SG design and foreign object properties (mass, size, etc), foreign objects entering the secondary side of the SG may locate on the tubesheet within the shell-to-tube bundle annulus region or the blowdown lane (tube lane). SG tubes are typically susceptible to foreign object damage in regions of high secondary feedwater velocity. Therefore the tubes near the shell-to-tube bundle annulus region (the periphery tubes) are most susceptible to flow induced foreign object tube wear/damage. It has been estimated by EPRI, in a review of industry data, approximately half of the tube wear events caused by foreign objects occurred in the outermost periphery tubes and approximately 90% of the tube wear events caused by foreign objects occur within the 3 tubes nearest the periphery. Therefore a minimal scope for a FOSAR is an examination of the shell-to-tube bundle annulus region (including periphery tubes) and the tube lane. The periphery tubes inspection may be achieved by articulating the camera angle to view into the bundle from the annulus region, without inserting the video equipment into the bundle. Visual inspections conducted in this manner provide reasonable assurance that foreign objects with potential to damage tubes located on the secondary face of the tubesheet will be identified, to the extent practical.

All foreign material that has the potential to damage tubes shall be removed from the SGs if reasonably achievable within the limitations of the equipment. Items that are removed or determined to be irretrievable and/or could cause damage to tubes by removing them shall be evaluated in the plant's corrective action program. Important details to include in the evaluation:

1. An estimation of the material and size of the object (diameter, length, and weight)

2. Tube row/column of the object

3. The estimated axial location of the contact

4. Whether or not the object is firmly lodged or able to move

5. Whether or not tube wear is a result of the object

6. Calculation of potential wear rate if the object moves and contacts tubes for the planned operating interval. This calculation shall include conservative assumptions regarding the object's size, the material of the object, tube vibration amplitudes and cross flow fluid velocities.

7. Whether past eddy current data shows the presence of the part.

When irretrievable foreign material has been identified, it shall be tracked and inspected at each scheduled primary side and secondary side SG inspection to identify changes that would require additional evaluation. Engineering analysis shall determine the inspection interval. Foreign material removed from the steam generators shall also be documented and trended. The type of material entering the SGs and potential for tube damage shall be considered in the analysis when determining the interval between primary or secondary side inspections. The EPRI Steam Generator Degradation Database provides a means for documenting and trending foreign material and associated tube damage.

If potential foreign objects are identified during an eddy current inspection, the objects shall be dispositioned. Options for dispositioning include performing a visual inspection in the area of the call, reviewing past and current eddy current data for wear, bounding the area with qualified eddy current inspection, and reviewing past visual tapes in the area.

If secondary side inspections confirm the presence of foreign objects, the description and location of the parts shall be recorded for consideration during eddy current examination. If primary side eddy current inspections are scheduled, the tubes in the area of the foreign objects should be examined to determine if any tube damage is present. Rotating probe or array probe inspections may be necessary if damage could be present in tube regions where bobbin inspection is not qualified for detection. Visual inspections may be considered as an alternative to eddy current inspection, but only if the visual quality and coverage is sufficient to convincingly demonstrate that tube damage is not present in the areas that could have been affected by the part(s). If a part is small enough to enter the tube bundle, visual inspection coverage should include the entire circumference of the tubes in areas potentially affected by the part. If tube damage is detected (i.e., not surface marks or superficial scratches) or considered likely based on visual inspection a need for tube integrity assessment shall be determined.

With replacement SGs, it is possible that the long-term plan would recommend performing FOSAR with or without cleaning and not performing primary side inspections. If this is the case, contingency planning shall be performed in the event foreign material is identified. Figure 10.2 illustrates this planning. A similar thought process should be documented for the case where primary side inspections are performed with no secondary side inspections planned.

When both primary and secondary inspections are performed, these activities should be coordinated to ensure that potential foreign objects identified by eddy current are able to be investigated by the secondary side crew. Parts identified by the secondary side crew should be communicated to the eddy current leads to reevaluate eddy current data for wear if necessary.

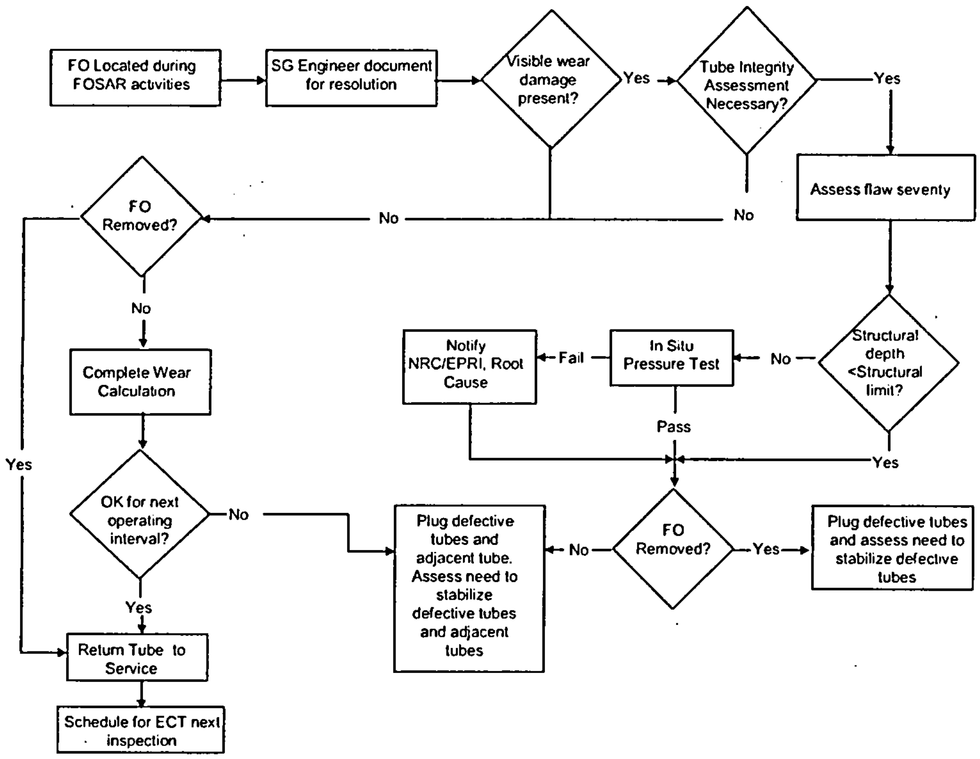

Figure 10.2 Contingency Planning for Secondary Side Inspection With No Planned Primary Side Inspection

10.6 Upper Internals Inspections

An upper internals inspection shall be performed and planned in accordance with the secondary side integrity plan for plants with recirculating steam generators to verify tube safety functions are not jeopardized by internals degradation. This inspection looks for evidence of corrosion, erosion, chemical deposits, or other conditions which may be present in the upper shell internals. Frequency of these inspections should be commensurate with observed and potential degradation Areas of inspection should include:

- Drain pipes and seal buckets
- Instrumentation taps (level transmitters, etc.)
- Demister banks
- Deck plates
- Downcomer barrels
- Wrapper transition to swirl vanes
- Primary separators
- Feedwater ring, feedring components, and support straps
- Swirl vanes
- Orifice rings
- Applicable welds
- Nozzles

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

Date: November 18, 2005

To: SGMP Technical Advisory Group
PMMP Executive Committee

Subject: **SGMP-IG-05-04,** Interim Guidance Regarding Adverse Trend of Foreign Objects in Steam Generators

Reference: Letter of 5/24/05 from Mark E. Reddemann to Utility Site Vice Presidents

Purpose:

The purpose of this letter is to provide interim guidance to the industry regarding control of foreign object intrusion into the steam generators. An SGMP Foreign Object Task Force was established by the IIG to address concerns detailed in the referenced letter as well as recent reportings by industry of foreign material issues.

After reviewing data from the EPRI Steam Generator Database and from recent operating experience, the Task Force developed a new chapter for the EPRI Steam Generator Integrity Assessment Guidelines, Revision 2 to incorporate lessons learned. In light of recent events, the IIG considers this chapter important guidance for control of foreign materials and that it should not wait until Revision 2 of the Integrity Assessment Guidelines is published; therefore, it is being issued as an Interim Guidance (see attachment).

This guidance shall be implemented within 6 months after receipt of this letter and will be in effect until the Revision 2 of the Integrity Assessment Guidelines is published.

Sincerely,

Jeffrey T. Gasser

Jeffrey T. Gasser
Executive Vice President and Chief Nuclear Officer, Southern Nuclear
Chair, PMMP Executive Committee

Attachment: Chapter 10, Maintenance of SG Secondary Side Integrity

cc: SGMP IIG
SGMP E&R IRG
SGMP NDE IRG
Jim Riley, NEI
Jeff Ewin, INPO
Carl Larsen, INPO
David Steininger, EPRI
Mohamad Behravesh, EPRI

Steam Generator Management Project (SGMP) Information Letters

1	*9/29/00*	*Womack –Sept 2000*
2	*10/25/02*	*SG Tube Leak – Comanche Peak*
3	*12/03/02*	*Seabrook Update – Axial Cracking*
4	*4/23/03*	*Exner – Oconee Unit 2*
5	*6/06/03*	*Exner – Diablo Unit 2*
6	*3/16/04*	*Womack – March 2004*
7	*9/14/04*	*Womack – Alloy 600TT*
8	*9/20/04*	*Womack – Automated Analysis*
9	*3/04/05*	*SGMP-IL-05-01*
10	*3/13/06*	*SGMP-IL-06-01*

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September 29, 2000

To: Steam Generator Management Program Utility Steering Committees
PMMP Steering Committee
Senior Representatives
Technical Advisory Group (TAG)

From: Lawrence F. Womack
Chairman, Steam Generator Management Program

Subject: Steam Generator Management Program (SGMP) Information Letter Concerning Lessons Learned from a Review of Recent Steam Generator Related Issues

References:
1. Letter, David Modeen to NEI Administrative Points of Contact, Approval of Formal Industry Position on NEI 97-06, Rev. 0, *Steam Generator Program Guidelines*, December 16, 1997
2. EPRI Final Report, TR-107621-R1, *Steam Generator Integrity Assessment Guidelines*: Revision 1, March 2000
3. EPRI Final Report, TR-104030, *PWSCC Prediction Guidelines, July 1994*
4. EPRI Final Report, TR-107620-R1, *Steam Generator In Situ Pressure Test Guidelines*, June 1999
5. EPRI Final Report, TR-107569-V1R5, *PWR Steam Generator Examination Guidelines: Revision 5*, September 1997

Introduction

The purpose of this letter is to provide you with timely steam generator information to consider when planning your plant's steam generator inspection, condition monitoring, and operational assessment (see Reference 1). The information presented below was developed under the auspices of the SGMP IIG and its supporting subcommittees from a review of steam generator issues related to the recent event at Indian Point 2, the integrity assessment performed at ANO 2, and the "Summary of 1999 INPO Steam Generator Review Visit Recommendations." Generally, the intent of the review was to identify if there exists a need to modify or at least clarify aspects of industry guidelines referenced in NEI 97-06. Additionally, this review attempted to identify whether broader issues exist beyond those specifically associated with the formal guidance now offered by NEI 97-06 and its referenced documents. It is not this letter's purpose to detail formal, specific changes (e.g., added emphasis, further clarification, provide additional information, etc.) to NEI 97-06 or its referenced guidelines. Such alterations must be developed through the defined protocol established for these documents. Appropriate changes to these documents, if needed, will be made by the applicable NEI and SGMP guideline committees after review of the items presented in this letter. This letter will be reviewed by the applicable committees, and areas where work is required to develop appropriate guidance will be identified and the work scheduled by year-end.

Discussion

Steam generators with degraded tubing present a particularly challenging problem of inspection, condition monitoring, and operational assessment. It is for this reason that industry imposed upon itself, in December 1997, the requirements of NEI 97-06 and its referenced guideline documents. Upon review of these requirements and supporting guidelines, it is concluded that a number of items need to be re-emphasized or further defined and explained. General areas identified from this review include issues associated with degradation assessment/operational assessment/condition monitoring, data quality, probability of detection (POD), in situ pressure testing of tubes, risk analysis, and steam generator program ownership and implementation. Specifics associated with these areas are presented below.

1. Degradation Assessment/Operational Assessment/Condition Monitoring

It is imperative that before a plant outage, the guidance presented in Chapter 3, *Degradation Assessment*, of Reference 2, be fully implemented.

In general, prior to the inspection of steam generators, all required preparatory actions – such as degradation assessment, site-specific performance demonstration for current degradation forms, site technique qualification, set-up of an analyst performance tracking system, review and implementation of current EPRI Examination Technique Specification Sheets (ETSS), and use of proper calibration standards – should be completed. In addition, the following items are emphasized:

a. The degradation assessment must be current with appropriate and accurate incorporation of industry experience associated with the types of degradation that can be expected and their associated growth rates. Arbitrary assumptions on growth rate, intended to substitute for lack of data, may prove inaccurate and non-conservative and must be avoided. Additionally, consideration should be given to potential initiators or accelerators of degradation, such as induced stresses from tube support denting, to accurately anticipate degradation.

b. Degradation growth rate determination should be done using industry-recommended techniques. It is imperative that industry data be reviewed and incorporated where applicable into the development of site-specific growth rate values. The SGMP's Steam Generator Degradation Database can be interrogated to identify plants exhibiting similar degradation forms. These plants should be contacted to obtain growth rate data for these forms of degradation. Additionally, growth rate data for specific degradation forms can be developed or obtained from EPRI reports such as Reference 3.

c. When a new type of degradation is discovered, an operational assessment must be performed using best available, industrywide data. If such data are incomplete, then reasonable, conservative, and technically supportable assumptions must be used in the analysis to allow safe and reliable operation of the plant in its next cycle.

d. Discovery of new degradation of significant extent within a given tube must be screened according to the criteria listed in Reference 4 and appropriate action taken. As indicated in Section 4.3 of this reference, *Additional Screening Considerations*, even if the subject degradation passes the screening criteria, but is considered to be a defect with unusual characteristics, consideration should be given to in situ pressure testing the affected tube.

2. Data Quality

a. Site steam generator examination guidelines should define data quality requirements in measurable terms, such as noise level. An appropriate definition that must be met to ensure detection of degradation at the required level should be developed prior to the inspection. Use of certain types of supplemental inspection techniques may reduce noise, enhance data quality, and exhibit better detection characteristics for a specific degradation mode. If acceptable data quality cannot be obtained for a given tube, the tube should be repaired or removed from service. Successful implementation of a supplemental inspection technique occurred at IP2 this year in their use of the high frequency probe for PWSCC degradation detection. This probe exhibited less sensitivity to noise from external tube deposits and was better able to detect inner diameter initiated tube flaws.

b. Steam generator site-specific examination guidelines should emphasize to the inspection analysts, including the resolution analyst, the potential significance of abnormal signals. Additionally, discovery of such abnormal signals during inspection should be communicated to the person responsible for steam generator integrity assessment.

c. It is emphasized that chosen NDE techniques should be site qualified so that plant conditions and their effect on detection and/or sizing are accurately quantified and accounted for in analysis intended to support satisfaction of NEI 97-06 requirements. For example, if plant conditions are such that acceptance criteria on signal/noise (S/N) cannot be met for a particular inspection device, appropriate adjustment to detection and sizing parameters must be made. The industry is in the process of defining an action plan for developing guidelines for

use in making this adjustment. Interim guidance on adjustments to applicable inspection parameters is expected by March 2001. Additionally, if needed, technical support should be solicited from the EPRI NDE Center.

3. Probability of Detection

a. Prior to an outage, steam generator conditions should be checked against the "NDE technique performance database" developed under Appendix H (see Reference 5). This database presents, for each NDE technique, an Examination Technique Specification Sheet (ETSS) that lists a technique's essential variables and assumptions. The performance database also includes raw eddy current data that can be analyzed to conduct probe comparisons of signal interference such as tube-induced eddy current noise. Steam generator conditions should be checked against this information to ensure that variables like probability of detection and measurement uncertainty are not unacceptably altered by significantly different conditions. If these conditions result in unacceptable values for variables important to "tube integrity assessment" analysis, use of alternative inspection techniques or appropriate adjustments to the subject variable (e.g., POD) and/or integrity analysis become necessary. The industry is continuing to develop appropriate guidelines for how these adjustments are made. Further guidance on this subject will be provided in the next revision (i.e., Revision 6) of Reference 5. In the interim, conservative engineering judgment and appropriate technical justification for applied adjustments should be incorporated in the integrity assessment. Additionally, confirmation of conformance to Appendix H essential variables and assumptions should be performed during the inspection. It is recommended that utility personnel contact the EPRI NDE Center for help, if needed, in the areas of POD adjustment and essential variable confirmation.

b. It must be noted that POD is a function of both technique and analyst performance uncertainty. Technique and analyst data for defining system POD performance are provided in the EPRI database. Guidance for development of this system POD is provided in Section 4.3 of Reference 2. However, because of recent questions received on this topic, industry will review and, if necessary, further develop these guidelines. In the interim, technical support should be solicited from SGMP personnel at the EPRI NDE Center and in Palo Alto.

4. In Situ Pressure Testing of Tubes

a. It is noted that selection of qualified NDE techniques for steam generator inspection is guided by the requirement to satisfy the performance criteria of NEI 97-06 as discussed in Reference 2. This requirement may need to be extended

further when in situ pressure testing of tubes is required. In situations of relatively difficult flaw evaluation with large uncertainty, it is recommended that supplemental NDE techniques and specialized data review be used to provide an improved, overall characterization of suspected flaws in tubes identified for in situ pressure testing. Some guidance in this regard is provided in Section 5.1 of Reference 4.

b. If in situ burst pressure testing of a given tube results in leakage to the extent that pump capacity is exceeded, an appropriate bladder should be located at the flaw and the tube re-tested as discussed in Reference 4.

c. Several issues regarding Reference 4 developed during the inspection and evaluation of steam generators at one plant. These issues involved the correct use of in situ pressure test results in bounding-type integrity analysis and application of an appropriate temperature correction in determining in situ test pressure. These issues were submitted to the NEI Review Board, which clarified the applicable guidance provided in Reference 4. It is emphasized that if there is a problem in interpreting NEI 97-06 or its referenced documents, the NEI Review Board should be consulted about the issue in an expeditious manner. This is especially true if the issue is associated with References 2 and 4 because of the potential for errors or misinterpretations having a significant impact on condition monitoring and operational assessment. Additionally, it is recommended that utilities periodically review the information available on the NEI Web site dealing with resolution of NEI 97-06 issues offered by the NEI Review Board. This review will help ensure that the best and latest industry guidance is being factored into steam generator inspections and tube integrity analysis.

5. Risk Analysis

a. If the performance criteria of NEI 97-06 cannot be satisfied or adequately evaluated when performing an operational assessment for a given plant operating time, risk analysis may be another way to support the operational assessment. However, it must be recognized there presently are limitations regarding the capability of available risk analysis and associated methodology. At present, industry has not provided sufficient and/or complete guidelines to follow for this type of analysis, although at least one plant has successfully used risk analysis (with NRC approval) to support extended steam generator operation with reduced tube structural integrity margin. One other plant does not appear to have been completely successful in using risk analysis to justify extended operation with reduced tube structural integrity margin. Preliminary risk analysis performed to date by the SGMP for industry has only been developed in support of alternate repair criteria that meet the performance criteria of NEI 97-06. This subject will be reviewed by the appropriate SGMP committee to identify further work in this area for 2001.

6. Steam Generator Program Ownership and Implementation

a. It is recommended that plants should have accessible personnel, knowledgeable in NDE and structural mechanics, who can integrate inspection results associated with unusual conditions and assess their implications for tube integrity. Poor quality data must be efficiently identified, rejected, and alternative inspection techniques identified and used to obtain good data for degradation detection and integrity assessment. It is recommended that a Level III inspection analyst work closely with these personnel.

a. Strong utility technical oversight must be instituted in the areas of tube integrity assessment and in-service inspection if vendors are used to implement these elements of the utility's steam generator program. This recommendation is made because of the importance of the program in establishing safe and reliable operation of the plant's steam generators. It is recommended that the utility be actively involved in establishing the program, implementing its requirements, and carrying out its procedures where appropriate.

c. Utility management must recognize that it is their prime responsibility to provide sufficient resources and support to personnel implementing a plant's steam generator program so that the referenced guidelines in NEI 97-06 are appropriately implemented and associated requirements met.

Finally, a general comment is noted. During resolution of plant issues, questionable tube burst test data were generated. Test results suggested that tube burst pressure was a function of the pressurization rate. Because of potential ramifications these data may have on generic industry tube burst correlations used in alternate repair criteria, industry initiated a pro-active investigation to resolve this issue with the NRC. This investigation is presently in progress. An interim recommendation for changes to Reference 4 will be provided by September 30, 2000. This issue clearly highlights the continuing need for utilities to review their actions in support of their steam generator integrity assessment to identify, in a timely manner, any issues that may generically impact industry. This will allow the SGMP to address these issues in an expeditious manner for industry and the NRC.

Conclusion

Based on this review, it is concluded that all of the areas noted in the above bullets are addressed to varying degrees in the guideline documents referenced in NEI 97-06.

During development of NEI 97-06, it was recognized by its authors that the referenced guidelines allow for flexibility within each site-specific steam generator program so that improvements in techniques and methodologies for managing steam generator degradation

can be realized and formal guidance enhanced. In this context, it does appear that certain areas of these documents can be improved or strengthened with further emphasis as to their importance (e.g., site-specific inspection technique qualification). In certain cases, the addition of more detailed information on how to implement a given recommendation or requirement – such as, a data quality specification and a methodology for its implementation, a POD defined from uncertainties associated with technique and analyst performance, and changes to proof test pressurization rates – is also appropriate. Industry is presently working on these issues and specific guidance will be provided as it is developed and approved.

As noted earlier, Revision 6 to Reference 5, which will offer guidance on some of these issues, is expected to be issued in March 2001. In the interim, technical support should be solicited from the EPRI NDE Center. Additionally, interim guidance on adjustments to a POD and development of a system-related POD is expected by March 2001.

cc Jim Riley, NEI
Dave Modeen, NEI
Alan Smith, INPO
David Steininger, EPRI

ELECTRIFY THE WORLD

EPRI

October 25, 2002

Steam Generator Management Program (SGMP) Technical Advisory Group
SGMP Senior Representatives
EPRI PMMP Steering Committee

Dear Committee Member:

Subject: SG Tube Leak at Comanche Peak Unit 1

The purpose of this letter is provide you with information on the recent steam generator tube leak at Comanche Peak Unit 1 and the subsequent actions that the utility has taken in response to this tube leakage. The IIG has been following this event and continues to monitor the situation for its potential generic implications.

Enclosed is a summary description of the leaking tube and the NDE techniques that were used in this and previous outages to detect and characterize the defect that led to tube leakage. The NDE IRG of the SGMP is studying this information in light of the existing guidance to assess the need for the development of any additional interim guidance. For the upcoming TAG meeting scheduled for December 10-13, 2002 in Naples. FL., a presentation by Comanche Peak has been included on the agenda to provide additional information. The NDE IRG will also report on its findings at that time.

Sincerely,

Kevin Sweeney
Section Leader, Steam Generator and Projects Group, Arizona Public Service
IIG Chair, EPRI SGMP

Enc.

Comanche Peak Unit 1 SG Tube Leakage

(3/4 x 0.043" Alloy 600 MA Tubing)

Background

On September 28, 2002, CPSES Unit 1 entered 1RF09 seven days early due to a steam generator tube leak. The leaking tube was identified as R41 C71 in SG2 between AVB 3 and AVB 4 in the freespan region. This tube was inspected in 1999 (1RF07) and 2001 (1RF08) with no recordable indications reported.

Summary

The leaking indication was determined to be an OD axial indication approximately 0.9" long as measured with the Plus Point Coil with an amplitude of approximately 6.2 volts on the 300 kHz channel. The 1RF09 bobbin amplitude was approximately 6 volts using the 550 kHz channel. The 1RF08 bobbin amplitude was approximately 1.6 volts on the 550 kHz channel. During insitu pressure testing the flow capacity of the pump was exceeded at 2.6 gpm with a pressure of approximately 2100 psi. During 1RF08 a single freespan indication was detected with the guidelines using the bobbin ding technique developed for South Texas which utilizes a 130 kHz differential channel rotated to 27 degrees looking for a phase <155 degrees. Tube R41 C71 inspection history was reviewed. The indication was present in 2001 but did not meet the phase angle calling criteria for freespan indications. The freespan flow chart required a flaw-like signal present on either 300kHz or 130 kHz differential. Flaw-like is defined in the procedure as "any channel > 0 percent through wall". The 300 and 130 kHz signals both reflected a 0% through wall using this criteria. Auto analysis rule based system is used as the primary analysis followed by a manual review and edit of the auto results. The primary (auto) and secondary (manual) analyst would call a free span differential (FSD) if it were >0% through-wall. This would then prompt a history review of the indication by resolution. The auto rule base used the ding calling criteria but only at reported ding locations. In the case of R41 C71, the ding presence was not detectable due to horizontal probe wobble in the U bend. The guidelines in place during 1RF08 provided the following:

> *Where site qualified sizing techniques exists, the analyst should assign percent values to indications of degradation. <u>However, signals may be observed that act like flaws yet cannot be quantified due to signal distortion. This can be caused by outside interference affecting the signal, such as denting, deposits, geometry of the tube, probe motion, expansions of the tube, etc.</u> In such a case, one of the appropriate I-codes may be used to characterize the indication. Appendix A contains the definitions of each I-code.*

There was no call made by the secondary analyst in the 2001 inspection at this location.

Corrective Action Summary

To improve POD for freespan ODSCC, the freespan flow chart was enhanced as follows: the window was opened on the phase and the criteria of >0 percent was removed. The definition of flaw like was revised to be from 20 degrees to 160 degrees on 130 kHz where the phase of the 100% TW was established at 27 degrees; and 550 kHz between 20 degrees and 200 degrees. The primary and secondary analyst would call (FSD) if the indication were within either of the phase windows. Any indication that meets this criteria would then receive history review for change by resolution. If change (>10 degrees or 0.5 volts or no previous signal over two previous ISI's) occurred, the tube was tested using plus point. This methodology applies the ding crack detection criteria to the entire freespan tube with or without the presence of dings. It was also determined during the Comanche Peak Unit 1 inspection that history look-back one ISI is not sufficient as some confirmed indications showed no change looking back one ISI but did exhibit change looking back two ISI's.

ELECTRIFY THE WORLD

EPRI

December 3, 2002

Steam Generator Management Program (SGMP) Technical Advisory Group
Steam Generator Senior Representatives
EPRI PMMP Steering Committee

Dear Committee Member:

SUBJECT: Seabrook Axial Cracking at Tube Support Plate Land Contact Points

As indicated during industry meetings this year and in NRC Information Notice 2002-21, indications of outside diameter stress corrosion cracking (ODSCC) in thermally treated Alloy 600 tubing were detected at the Seabrook station during its eighth refueling outage in May of this year. As indicated in the NRC's correspondence, this finding is considered important to the steam generator industry, as no confirmed instances of stress corrosion cracking of Alloy 600TT tubing had been previously reported in domestic steam generators.

As also reported previously, Seabrook elected to remove two (2) tubes for metallurgical analysis to characterize the degradation and identify the root cause. The purpose of this letter is to provide you with updated information on the apparent cause of the ODSCC that occurred at Seabrook during the spring of 2002 and disseminate an eddy current inspection methodology for identifying tubes that may be susceptible to this condition.

The NDE IRG of the SGMP is further studying this information in light of the existing guidance to assess the need for interim guidance or if additional technical protocol is required. For the upcoming TAG meeting, scheduled for December 10-13, 2002 in Naples, FL., a presentation by Seabrook has been included on the agenda to provide additional information.

Sincerely,

Kevin Sweeney
Section Leader, Steam Generator and Projects Group, Arizona Public Service
IIG Chair, EPRI SGMP

Attachment

CORPORATE HEADQUARTERS
3412 Hillview Avenue | Palo Alto CA 94304-1395 USA | 650.855.2000 | Customer Service 800.313.3774 | www.epri.com

Attachment

Root Cause - High residual stress caused by the manufacturing process in a small subset of tubes. Seabrook has determined it is not a new degradation mechanism and it is also not considered active for the balance of the tubes other than those identified (21 tubes) in D S/G.

Two tubes were pulled, one from the hot leg and one from the cold leg. Both tubes were from Heat 1374. The largest indication was measured in TSP 4 on the hot leg pulled tube and was tested to 7,000 PSI. The tube did not burst or leak. Testing was terminated at 7000 PSI to preserve the segment for laboratory testing.

Seabrook initially identified 15 tubes with a total of 42 indications at TSP locations. During the root cause investigation an electromagnetic signal was discovered to be unique to the 15 tubes as shown in Figure 1b. Thirteen of the 15 tubes were from Heat 1374. The other two tubes were from Heat 1456 and 1457. Subsequently, Seabrook identified six additional tubes that contain similar electromagnetic responses. These additional tubes were deemed no detectable degradation (NDD) at the spring 2002 inspection, but will be repaired at the next refueling outage. All tubes that showed the electromagnetic response, Figure 1b, were located in the "D" steam generator.

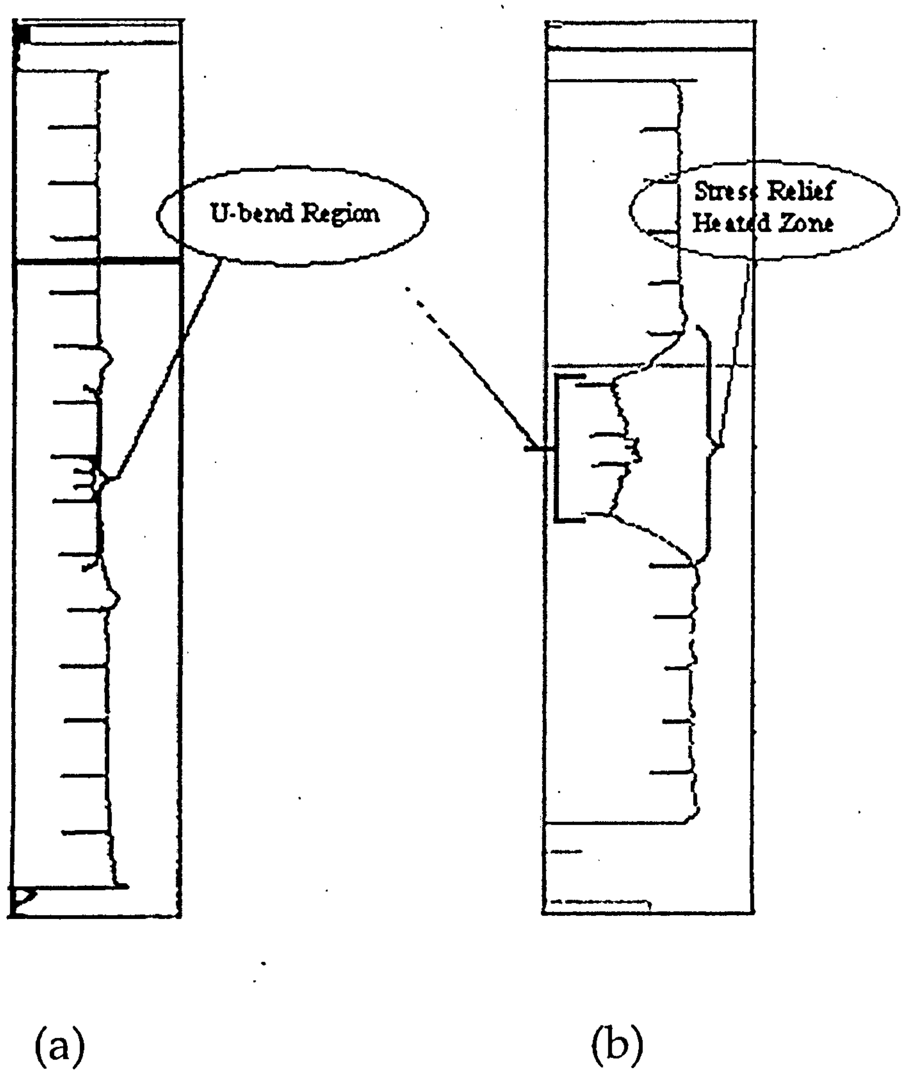
The pulled tubes showed less than optimum micro-structure, but still acceptable and within the band for thermally treated (TT) tubing. The average residual stress in the pulled tubes was 16-26 ksi. Archive tubing from Heats 1374, 1456 and 1457 identified the average residual stress to be 1-3 ksi, which is typical for a thermally treated tube. It is believed that the residual stress from cold work on the surface maybe as high as yield. If the operating stress in the tube is combined with the residual stress, the values approach 40 ksi, this significantly increases susceptibility to cracking.

Review of prior eddy current data showed that 25 of the 42 indications had minor precursors present in the May 1999 inspection.

A screening technique was developed by Westinghouse for rows 11 through 59. This process looks at the relative voltage offset between the straight length and the bend. A lower voltage offset could mean that the tube stress may be approaching that of a mill annealed tube as shown in Figure 2b. An example of the eddy current response is provided in Figure 1 for rows 1-10 and Figure 2 for rows 11 and above. Additional information regarding this methodology can be obtained by contacting Gary Henry (EPRI NDE Center) at (704) 547-6132 or Gary Boyers (FP&L) at (561) 694-4909.

Figure 1

Thermally treated tube with U-bend stress relief (a) versus Thermally treated tube that was cold-worked and U-bend stress relieved (b)

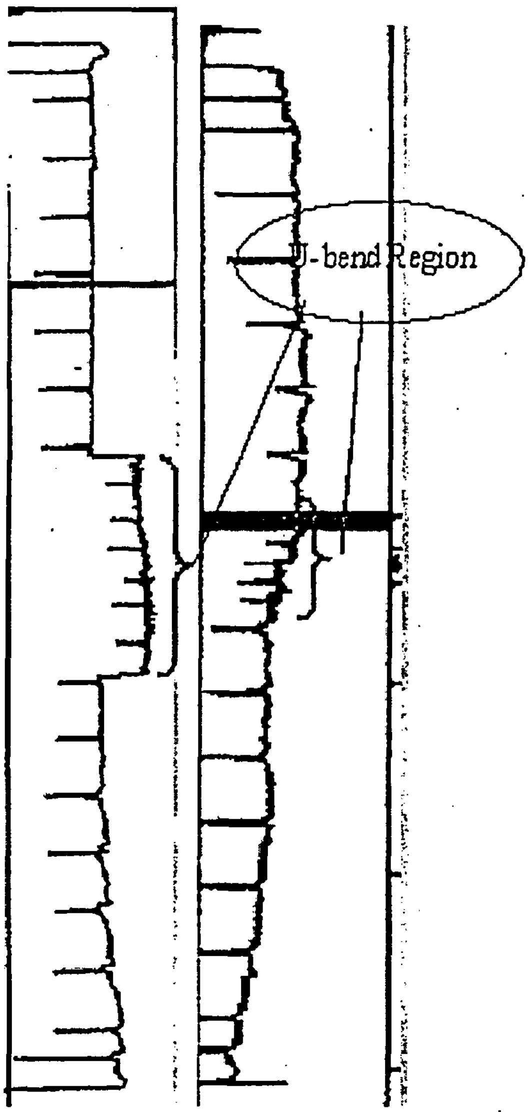


(a) Normal 150 kHz Eddy Current strip chart for a Row < 10 thermally treated tube

(b) Seabrook degraded tube, 150 kHz Eddy Current strip chart for a Row <10 thermally treated tube

Figure 2

Thermally treated tube with no U-bend stress relief versus a mill annealed tube



(a) (b)

(a) Normal 150 kHz Eddy Current strip chart for a Row > 10 **thermally treated** tube

(b) [this one is NOT Seabrook]Normal, 150 kHz Eddy Current strip chart for a Row >10 **mill annealed** tube

Pacific Gas and Electric Company

Diablo Canyon Power Plant
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805.545.6000

April 23, 2003

To: Steam Generator Management Program (SGMP) Utility Steering Committees
PMMP Steering Committee
Senior Representatives
Technical Advisory Group (TAG)

From: Bob Exner
Chair, SGMP Issues Integration Group

Subject: Oconee Unit 2 In Situ Pressure Test Failure

Tube 37-27 in Unit 2 **OTSG** B failed to reach the adjusted full three times normal operating delta-p test pressure of 4300 psig during in situ leak testing in violation of performance criteria. The root cause was determined to be masking of a flaw by the combination of dent and volumetric flaw from a manufacturing burnish mark.

Utilities should assess and take appropriate action to determine the impact of the masking effects by combination signals such as dents and manufacturing burnish marks.

The tube contained an axial indication in a dent at **5.41** inches above the fifteenth tube support plate. The axial indication was measured at 77 percent PDA and was two inches long. It was selected for in situ pressure test.

Historical review of the March 1998 and November 1999 data indicates a volumetric signal approximately one inch long leading into the dented area as well as some lobe opening associated with the dent. The historical review of the 2001 data also indicates a volumetric signal approximately one inch long leading into the dented area. However, after reviewing the 2001 data, the dented area appears to indicate a phase rotation indicative of axial flaw in combination with the dent. The 2002 data clearly indicates the flaw at the dent has propagated to the point of being the major signal of influence in length and signal response.

Several general characteristics of the indication(s) were observed during the review of the historical, 1998 through 2001, and current data:

- The historical bobbin coil data indicates the presence of a volumetric signal (manufacture burnish mark) associated with the dent traceable to the 1993 RFO.
- Prior to the 2002 RFO, the signal response appears to be a combination of signals in close proximity to each other along the axis of the tube.
- All of the data reviewed indicates an area between the fifteenth TSP and the dented area has a signal response, with the Plus Point coil indicative of a volumetric indication leading into the dented region.
- It is reasonable to conclude, from reviewing the current and historical data, that the signal response could have realistically been interpreted to be indicative of a volumetric manufacturing burnish mark and resolved accordingly. It is also reasonable to determine the signal response of the dented location should have been reported as an axial flaw associated with the dent as early as 1998.

Simply put, the flaw was thought to be a manufacturer's burnish mark superimposed over a dent and that is why it was left in service in previous years. The reality is that there are dent, volumetric signal (MBM), and axial flaw components to the signal.

The combination of volumetric flaw and dent served to mask small cracks and make the large axial flaw uncalled until 2002. This combination also served to confuse the analyst. All indications of dents and volumetric flaws in close proximity to each other are now considered a precursor signal and masking combination that affects detectability of flaws.

All tubes with similar indications were removed from service. Similar indications will be included in the site-specific qualification testing.

This was a degradation of margin. The tube met the limiting accident condition (main steam line break) pressure (2898 psig) and did not leak.

Sincerely,

Bob Exner
Project Manager, Steam Generator Replacement Project – Diablo Canyon Power Plant
Chair, SGMP Issues Integration Group

cc Jim Riley – NEI
Jeff Ewin – INPO
David Steininger – EPRI
Mohamad Behravesh – EPRI

Pacific Gas and
Electric Company

June 6, 2003

To: Steam Generator Management Program (SGMP) Utility Steering Committees
PMMP Steering Committee
Senior Representatives
Technical Advisory Group (TAG)

From: Bob Exner
Chair, SGMP Issues Integration Group

Subject: U Bend Cracking at Diablo Canyon Power Plant Unit 2

During the recent 2R11 outage at Diablo Canyon Power Plant (DCPP) Unit 2, several circumferential cracks were discovered in steam generator tube rows 3 through 10 U bends. The purpose of this information letter is to communicate the circumstances of this event and the information known to date about the cause of this degradation so that other utilities may make informed decisions about their steam generator (SG) programs.

Background

DCPP Unit 2 has Westinghouse Model 51 SGs with A600 MA tubing. Unit 2 has all Westinghouse Blairsville tubing. PG&E heat-treated the rows 1 and 2 U bends in the first outage and has inspected rows 1 and 2 U bends with rotating probes capable of detecting circumferential, as well as axial, flaws every outage since the first in-service inspection (ISI). PG&E has inspected the outer rows (3+) with bobbin probes. In the first outage after heat treatment, six larger circumferential PWSCC flaws were detected in row 1 that initiated prior to heat treatment. Over the years, a number of small axial PWSCC flaws, and a few small circumferential PWSCC flaws, have been detected in rows 1 and 2 U bends. Since heat treatment, 54 row 1 tubes have been plugged due to axial PWSCC and five due to circumferential PWSCC. Two small axial PWSCC flaws were detected in row 2 tubes and also plugged. These row 2 flaws caused an expansion to row 3 with a rotating probe, where nothing was found.

Starting near the end of cycle 9, a small primary-to-secondary leak was detected in Unit 2. This leak slowly increased and eventually reached about 6 gpd in cycle 11. The leak was determined to be in SG 2-4. During the 2R9 and 2R10 outages, attempts were made to find this leak through very careful plug inspection and review of U bend eddy current data. These attempts were unsuccessful, so a decision was made to conduct a secondary side pressure test during 2R11 to find the source of the leakage. The pressure test identified leakage from both the HL and CL of tube R5C62 in SG 2-4. Eddy current examination with a +point probe detected a number of short circumferential ID cracks throughout the U bend in this tube. Several of these indications were estimated to be through-wall. All of the indications were relatively short (about 0.25" or less).

PG&E decided to inspect all Unit 2 U bends with +point in order to verify the extent of U bend cracking. Eleven additional tubes were found with U bend circumferential cracks. Table 1 shows the distribution of all cracks found during the inspection expansion No cracks were found past row 10. Table 2 shows the orientation of the cracks related to the tube axis (all cracks were in the flanks, i.e., at about 90 or 270°). Eddy current data from these inspections has been added to the EPRIQ website for use by the industry.

Actions Taken by PG&E

In addition to the 100% inspection of all U bends with +point, PG&E took the following actions to resolve this issue during the 2R11 inspection:

1. A visual inspection was performed of all U bends with cracks and some NDD U bends for comparison. The visual results confirmed what appears to be short PWSCC cracks in the flanks of the U bends (see Figure 2 for locations). The visual indications aligned well with the eddy current indications.
2. In-situ leak and pressure testing was performed on all tubes with U bend flaws. All tubes passed the 3xNODP pressure test. Only R5C62 leaked (at a small rate) up to 3xNODP pressure.
3. An analysis and sample +point inspections were performed to verify that this phenomena was not also occurring in straight sections of tubing
4. U bend bobbin data was carefully reviewed. Some of the flaws in R5C62 had a detectable bobbin response, once the flaw location was known from +point. No bobbin response could be found for any of the other cracked U bends. Previous bobbin data was reviewed for R5C62 for those locations that had a detectable 2R11 bobbin response. These signals (declining in number and voltage) were traceable back to 2R7 (1996), leading to the conclusion that these small circumferential flaws are slow-growing.
5. PG&E collected U bend data with two array probes (X-Probe and MHI Intelligent Probe) to help qualify one or both of these probes for inspecting U bends in future outages.
6. A root cause analysis was performed. This analysis concluded that residual stress from tube bending caused PWSCC to develop in the U bend flanks of a limited number of tubes after a number of years at elevated temperature. To date, this analysis has not clearly determined the row or radius where residual stress is low enough to preclude eventually developing PWSCC in a small number of U bends. DCPP experience has shown that 14 EFPY at 603F Thot can cause circumferential PWSCC to develop in U bends out to row 10.

Summary Information

In summary, this letter transmits the following informational points:

1. Eddy current data for the DCPP U bend circumferential cracks has been placed on the EPRIQ website for use by the industry in addressing this issue.
2. The use of a bobbin probe to inspect U bends that are susceptible to circumferential cracking caused by residual stress is not an acceptable practice.
3. A carefully conducted secondary pressure test can be very effective in finding the source of low-level primary-to-secondary leakage.
4. Low-level primary-to-secondary leakage was an indicator of an abnormal situation that needed to be investigated beyond the use of eddy current testing.
5. The type of cracks observed were short and deep and did not exhibit a tendency to link up; therefore, the tubes were structurally sound, all passing 3xNODP in-situ pressure tests.
6. The type of cracks observed seem to be slow-growing and to occur in a limited random number of tubes over time. No obvious differences could be found between the tubes that cracked and other tubes.

7. Old test data and reports are not very clear about which rows may or may not be susceptible to eventual flank cracking form residual stress. It is a matter of time at temperature, with shorter radius U bends seemingly more susceptible. To date, no critical area has been developed.
8. The SGMP is considering additional contract work to pull together old test data and industry experience to develop a critical area that may be used to guide future U bend inspection scope.

Sincerely,

Bob Exner
Project Manager, Steam Generator Replacement Project – Diablo Canyon Power Plant
Chair, SGMP Issues Integration Group

cc Jim Riley – NEI
Jeff Ewin – INPO
David Steininger – EPRI
Mohamad Behravesh – EPRI

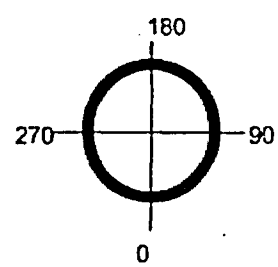
Attachment

Table 1 – Summary of U bend Circumferential PWSCC

SG	Row	Col	Axial Position	Number of +Point Indications
21	5	54	throughout bend	7
22	4	51	throughout bend	21
22	10	19	throughout bend	2
23	3	86	CL tangent	2
23	3	93	CL tangent	1
23	4	52	CL tangent	1
24	5	60	throughout bend	3
24	5	62	throughout bend	35
24	5	68	throughout bend	5
24	6	23	throughout bend	5
24	6	53	CL tangent	1
24	7	52	throughout bend	9

TABLE 2– ANGULAR POSITION OF THE INDICATIONS BASED ON THE DOWN LOCATOR

SG	ROW	COL	POSITION (degree)	POSITION (For Indication on Opposite Side)
21	5	54	277°	-
22	4	51	272°	89°
22	10	19	272°	-
23	3	86	300°	105°
23	3	93	302°	-
23	4	52	302°	-
24	5	60	287°	-
24	5	62	278°	88°
24	5	68	299°	-
24	6	23	294°	-
24	6	53	-	86°
24	7	52	273°	-



Section
Defect Orientation
Viewed From Hot

Pacific Gas and
Electric Company

Lawrence F. Womack
Vice President
Nuclear Services

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March 16, 2004

PMMP Utility Steering Committee
SGMP Senior Representatives
SGMP Technical Advisory Group (TAG)
E&R IRG
NDE IRG

Subject: SGMP Information Letter on Status of Integrity Ad Hoc Committee and Development of Tools for Noise Measurement and Monitoring

Dear Committee Members:

The purpose of this letter is to provide a status update, prepared by the E&R IRG, on the Integrity Ad Hoc Committee activities and the plans for developing tools for measuring noise and adjusting POD and sizing uncertainties if necessary.

Background/Status

The integrity tools program has been underway since 2001 to develop protocol, procedures, and necessary software to obtain system performance indices for EPRI ETSS datasets. The original plan was as follows:

1. Decide on a pilot dataset. *Complete*
2. Gather all ODSCC axial data from plants and user's groups that were not included in the EPRI ETSS datasets. *Complete*
3. Conduct a peer review among NDE experts and integrity experts to approve datasets for ODSCC axial indications between the top of the tubesheet and the U-Bend. *Complete (still need peer review signoffs)*
4. Determine appropriate method for measuring noise for tube integrity. *Complete*
5. Conduct analyst testing (performance demonstration) to obtain a "system performance." *Planned for summer 2004*
6. Validate methodologies for noise measurement and POD and sizing adjustments.

Much progress has been made; however, the performance demonstration will not be completed in time to provide the necessary validation of the tools prior to September 1, 2004, in time for full implementation of the EPRI Examination Guidelines, Revision 6 noise requirements.

Additional interim guidance is being issued by the NDE IRG by letter dated March 16, 2004.

Update on the Proposed Approach for Noise Measurement

In July 2002, various noise measurement methods were described to the Integrity Ad hoc Committee and a methodology was approved. This methodology is documented in an EPRI report, "Guidelines for NDE and Destructive Exam Data Acceptability for NDE POD and Sizing Performance Demonstrations." This report is on the EPRIQ Web site under "Tools for Integrity." This document is meant to facilitate the pilot program for ODSCC and, if successful, would be the guidance to the industry for noise measurements for tube integrity.

The approved methodology for noise measurement and monitoring as part of the tools program will be based on peak-to-peak amplitudes with associated phase angle and vertical maximum amplitude. The areas of interest for tube integrity purposes are the areas where cracking is expected and would apply to the technique used to detect cracking. For example, for expansion transition, the transition is the area of interest for the RPC probe.

There are two methods that need to be validated for obtaining appropriate site POD in the presence of noise. The first method is a Monte Carlo noise adjustment method. This requires a 3D POD from a performance demonstration. Site POD can be adjusted with alternate noise distribution. The basic principle in this method is that the ETSS data set will have a POD based on the signal-to-noise ratio and a structural parameter (such as depth). Through a Monte Carlo process, the plant noise distribution can be sampled and the POD adjusted for the plant noise. If plant noise is less than the dataset, plant POD is better than the ETSS; if plant noise is worse, plant POD will be worse. This approach has been demonstrated to work with available data.

The second method is for ETSS data sets that have not been through a performance demonstration. This method is an extension to the Beren's model, which is a statistical model that has been used in the military for many years. The model predicts POD given signal amplitude versus a structural parameter, a noise distribution, and an analyst reporting threshold distribution. This model is expected to be able to be used for most of the existing ETSSs and replace the need for a performance demonstration. However, it has not been validated.

Plans for Tool Development

1. Expeditiously validate the Beren's model with existing data sets that have performance demonstration results.
2. Develop a specification for a system to measure and monitor noise. This should be only an adjustment to existing systems.
3. Determine the best vendor and modify software.
4. Perform noise measurements using the new tools and the new software at a pilot plant.
5. Perform DQV/DQM at the pilot plant, including noise in the area of interest, and store necessary data for traceability.
6. Issue guidance for implementation.

The current schedule supports a pilot plant demonstration in the fall of 2004.

Sincerely,

Lawrence F. Womack
Vice President, Nuclear Services-Diablo Canyon Power Plant
Chair, SGMP Senior Representatives

cc Jim Riley – NEI
Jeff Ewin – INPO
David Steininger – EPRI
Mohamad Behravesh – EPRI

SdEliF Jdvdg
HbfvilF Frpsdq/

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September 14, 2004

PMMP Utility Steering Committee
SGMP Technical Advisory Group (TAG)
E&R IRG
NDE IRG

Subject: SGMP Information Letter on an Example Methodology for Screening of Alloy 600TT Tubing for the Seabrook Elevated Residual Stress Issue

References:

1) E-mail Lagally (Westinghouse) to Mayes (Duke Power), dated 5/29/03, "Minutes from 4/13/03 Ad Hoc Meeting"
2) Information Notice on Seabrook cracking
3) SG-SGDA-02-37, Revision 2, "Seabrook Tube Cracking Root Cause Evaluation Report," April 2003
4) SG-SGDA-02-35, Revision 1, "Seabrook Steam Generator Tube Examination," April 2003

Dear Committee Members:

The purpose of this document is to provide a recommendation to the industry for appropriate and conservative actions to identify tubes with potentially elevated residual stress in Alloy 600TT tubing manufactured at the Westinghouse Blairsville facility (see Table 1). The need for a technical recommendation was discussed in an ad hoc meeting between the industry and Westinghouse (Reference 1). This methodology was provided by Westinghouse. These recommendations should be considered upon receipt of this letter.

Background

In May 2002, outside diameter stress corrosion cracking (ODSCC) was confirmed in one of the Seabrook (Model F) steam generators (SG's) in a small number of tubes. The details of the observed cracking were documented in an Information Notice (Reference 2). The root cause evaluation performed for Seabrook is documented in Reference 3.

Laboratory examination of the tubes pulled from Seabrook (Reference 4) revealed that both the hot leg (HL) and cold leg (CL) tubes exhibited an elevated level of residual stress, which was found to exist over the entire length of the pulled tubing (about 175"). The manufacturing processes were examined in detail, but no specific process failure was identified that resulted in the elevated residual stress. However, since the residual stress was found to exist over the entire length of the pulled tube, and on both the HL and CL pulled tubes, the root cause examination focused on the manufacturing operations that could have the potential to result in residual stresses over the entire length of the tubes. By process of elimination, only the straightening and polishing operation was considered to have this potential. Despite the fact that no definitive proof was found that tubes that were restraightened after thermal treatment (permitted by the manufacturing procedures, but requiring thermal treatment afterwards), it was generally believed that this process must have been the source of the high residual stress found in the pulled tubes. Since all tubes, short rows and long rows, are processed the same prior to U-bending, and since no straightening and polishing was performed after bending the U-bends, <u>all tubes, short row and long row, are considered to be equally susceptible to elevated residual stresses</u>.

In summary:

1. The principal cause of the cracking found in the Seabrook tubes was elevated residual stress.
2. The source of the residual stress was not specifically identified, but is believed to be due to an anomalous manufacturing process (i.e., straightening and polishing after thermal treatment without subsequent thermal treatment).
3. Cracking is not related to any specific material composition (i.e., a material heat).
4. Because the susceptible tubing condition is probably related to the manufacturing process, the potential for elevated residual stress is the same in short row tubes and long row tubes.

After restart of the Seabrook plant in 2002, six additional tubes were identified among the short row tubes in SG-D with the characteristic EC signal (see below) that indicated that the tubes may exhibit elevated residual stress. During the October 2003 inspection of Seabrook, three of these tubes were reported with ODSCC. No other tubes in any of the SG's were found to be degraded by ODSCC.

During the November 2003 inspection of the Braidwood 2 SG's (Model D5, Alloy 600TT tubing manufactured at Blairsville), ODSCC was confirmed in three long row tubes. A review of the Braidwood tubing had been performed prior to the inspection to determine if any tubes exhibited the characteristic signal indicating an elevated residual stress condition in the short row tubes, and also to identify the long row tubes with U-bend bobbin offsets (see below) that were outside the minus 2-sigma statistic of the entire SG population of offsets. All three degraded tubes were among the tubes identified with small U-bend offsets.

Diagnostics

The Seabrook experience indicated that the bobbin signal could be used to identify the elevated residual stress condition among the short row tubes that were stress-relieved in the U-bends. For the Model F, this is rows 1-10; for the Model D-5, this is rows 1-9; and for the Models 44F and 51F, this is rows 1-8. This was discussed at an ad hoc meeting between the industry and Westinghouse (Reference 1). The following statement was issued as a result of the meeting:

> "It should be clearly understood that bobbin coil eddy currents are not indicating or measuring tensile or compressive residual stresses. The signal received by the bobbin coil probe is influenced by conductivity that is affected principally by microstructural and dimensional factors. A major microstructural factor is the amount of cold work within the tubing wall thickness, although factors such as grain size and distribution of carbide and inclusion phases will also have an effect. The major dimensional factors are variations in the tubing diameter and wall thickness. In a U-bend, there will be continuous variations of diameter, wall thickness, and cold work around the bend. In straight sections, the influence of the dimensional factors should be low, and signals created by cold work should dominate. If the cold work is uniformly applied, it does not have to increase residual stresses. Cold work will change the dislocation density within the material and will influence conductivity. Residual stresses are created by non-uniform plastic deformation (strain/cold work) that will [cause an] increase in the density of dislocation or lattice defects. Lattice defects influence electrical conductivity. In the case of U-bends and straight tubing lengths, the cold working process is generally a non-uniform bending process and is likely to produce both tensile and compressive residual stresses in the tubing wall thickness. Explicitly, the 'Seabrook Signature'[1] is not due to residual stresses but due to reduction of cold work within the [post U-bending] thermally treated portion of the tubes."

[1] In this context, "Seabrook Signature" refers to the unique bobbin probe signature common to the degraded tubes in the short rows, rows 1-10, at Seabrook.

Short Row Stress-Relieved Tubes

The characteristic bobbin signal (i.e., "Seabrook Signature") for the stress-relieved tubes is shown in Figure 1. This response was common to all of the degraded tubes in Seabrook SG-D, plus six other non-degraded tubes, also in SG-D, that remained in service until November 2003. The signal characteristic is the direct result of the stress relief process.

Assume that a straight tube with residual stress is bent into a short row U-bend. The tube is then stress-relieved; however, only the U-bend plus a short length of the straight legs below the tangent points are stress-relieved, since only the center region of the furnace was activated. The beginning and end of the heat-affected zone is visible on the bobbin signal as shown in Figure 1. The result is a tube with residual stresses in the straight legs, but essentially no residual stresses in the region that was stress-relieved. The bobbin probe "sees" the difference in material condition (different conductivity) of the stressed (strained) and stress-free region of the tube. For the short row tubes with the characteristic signature, the stress-free region is the U-bend. For normal short row tubes that are essentially stress-free prior to U-bending, the entire length of the tubes is "stress-free," resulting in the essentially straight-line signal shown on Figure1a.

Long Row Tubes

The long row tubes are not stress-relieved after bending the U-bends. Thus, for a normal thermally treated tube without elevated residual stress, the U-bend is the stressed (strained) region of the tube. Since the bobbin probe "sees" the different material condition resulting from strain, the normal bobbin signal shows a sharp offset at the tangent point, and returns to the tube null at the opposite tangent point (Figure 2).

Unlike the short row case, there is no unique basis of comparison to differentiate between acceptable and unacceptable U-bend offsets. However, the tube manufacturing process is the same for thermally treated and mill-annealed tubing, except that the mill-annealed tubing is not thermally treated prior to bending the U-bends. Thus, the final operation prior to bending the U-bends for mill-annealed tubing is straightening and polishing, processes that cold work the material and result in residual stress in the tubes. Therefore, a reasonable basis of comparison for the thermally treated tubes may be the mill-annealed tubes. Both mill-annealed and thermally treated tubing bundle data are available for every size of Westinghouse-manufactured tubing (7/8", ¾", 11/16" dia.).

This hypothesis was evaluated for several plants with Alloy 600TT tubing. The U-bend offsets were measured for an entire bundle of mill-annealed tubing and for all of the SG's with thermally treated tubing. Figure 3 shows a typical result of this type of study. Although there is a clear difference between the thermally treated and the mill-annealed tubing populations, the scatter of the populations overlap slightly. Therefore, no absolute criterion based on this comparison is available.

A relative criterion can be employed in which the outliers of the population are identified. In this approach, the statistics for the population of U-bend offsets are developed based on the entire population of tubes in each SG. A theoretical basis exists to fit the population with a straight line, although the R^2 value can be expected to be low due to the larger scatter in the populations. The population standard deviation (sigma) is calculated, and a conservative choice of criteria is made to determine potentially susceptible tubes. A minus 2-sigma (population standard deviation) criterion is recommended. Only the lower 2-sigma limit is of importance.

Methods - Short Rows

Evaluation of the bobbin traces for the stress-relieved rows[2] was based on the presence or absence of traces similar to the "Seabrook Signature" shown in Figure 1. Experience from prior application of the low row screening suggests that it be performed manually or, at least, that a manual over-check of an auto analysis be performed. A manual review of the original screening for Seabrook identified two additional tubes with a bobbin signal characteristic that was similar to the signature characteristic.

Methods - Long Rows

For the long rows, i.e., tubes that were not stress-relieved in the U-bend region, measurements of the U-bend offsets should be made at both the HL and the CL a short distance above and below the tangent point to avoid the tangent point signal and also the top tube support plate signal. Care must be exercised that a consistent setup is used by all analysts, and that appropriate corrections are made for the specific standards and testers utilized during acquisition of the field data. Failure to do this will result in excessive scatter in the data. The measurements may be made using auto analysis.

Significant data scatter is expected among the measurements for long row offsets. The recommended method for minimizing the data scatter is to set an amplitude on the absolute channel for the 4x20% FBH. This is done by reviewing the data for the standards and reapplying a conversion factor for each calibration group. The calibration basis used is 4.00 Vpp on the 4x20% standard defect on the measurement channel[3].

The rationale for measuring the U-bend voltage offsets at both the HL and the CL is that the start and end of the bending process produces different strains in the tubes and hence different offset values[4]. Thus, a requirement was established that <u>both</u> the hot leg and the cold leg measurements must be below the chosen threshold offset value for the tube to be considered more susceptible.

The following summarizes the recommended process and criteria for the long row tubes:

1. Bobbin voltage offset measurements should be made at the HL and CL, being careful to avoid both the top TSP and the tangent points.

2. The population statistics should be developed to determine the minus 2-sigma (standard deviation) values for the entire population.

3. Both HL and CL measurements on any tube must be less than the specific minus 2-sigma value for the row number of the tube for the tube to be considered "susceptible."

4. The criterion is not absolute and requires judgments to be made. However, it appears to be a reasonable basis to define tubes that should be monitored.

5. The criteria appear to be SG model-specific. At least one bundle of tubes of the same design but from Alloy 600MA should be analyzed to provide an "anchor point" for the evaluation. The anchor point provides a basis to demonstrate that the thermally treated tubes are clearly different, and validates the conservatism of the minus 2-sigma criterion.

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[2] For 11/16" dia. tubes, rows 1-10; for ¾" dia. tubes, rows 1-9; for 7/8" dia. tubes, rows 1-8.

[3] For 11/16" dia. tubes, 150 kHz; for ¾" dia. tubes, 130 kHz; for 7/8" dia. tubes, 100 kHz.

[4] The manufacturing process for the SG's provides no assurance that the start and end of the U-bending process correlates with the HL and CL in any or all SG's.

6. SG-to-SG variations require that more than one MA bundle be evaluated to assure that the comparison is not non-conservative. This requirement may be relaxed if sufficient data become available to demonstrate that the offsets for different MA tube bundles for each tube size are essentially the same.

Susceptible Tubes

Tubes that are identified as "susceptible" based on the criteria above are not defective tubes. They are simply tubes that may be more likely to exhibit an earlier onset of corrosion than the tubes with a greater offset. Indeed, of the six tubes that were identified as "susceptible" in Seabrook SG-D that remained in service after the 2002 inspection, only three were found to be degraded during the subsequent inspection in 2003. The proper response for the tubes identified as "susceptible" is to regularly monitor them for signs of degradation precursor signals, and to factor this information into any decision for extended operating intervals between inspections.

General Recommendations for Inspections

Consistent with the presentations and minutes from the April 2003 ad hoc meeting of a committee of industry and Westinghouse personnel (Ref. 1), the following recommendations apply for examining the U-bend bobbin voltage offsets to identify tubes that may potentially exhibit elevated residual stress in the straight legs:

A. Plants that perform 100% bobbin inspections at every refueling outage (cycle lengths typically 18-24 months) need not review the inspection data for U-bend bobbin offset voltage. The normal inspections are expected to identify development of any potential degradation without significant risk of degradation progressing to a leakage condition during the operating cycle.

B. For plants not performing 100% bobbin inspection programs each refueling outage but with inspection intervals less than or equal to 36 months for each SG, it is recommended that screening for potential elevated residual stress conditions be performed to identify precursor signals in tubes with potential elevated stress conditions. For example, a tube that is identified with a voltage offset (short row) or a very small voltage offset (long row), e.g., "signature tubes," that also displays a precursor signal such as a distorted support plate (DSI) signal, should be removed from service, whether or not the signals are confirmed by subsequent RPC testing. Indications at support plates that are determined to be caused by explainable causes such as MBM's or loose parts may be excluded from this preventative plugging guidance with confirmatory techniques. Tubes that are identified as "signature tubes" without the presence of a precursor signal should be marked for tracking at future inspections, but may be kept in service.

   The Seabrook data indicate that the largest indication progressed from non-detectable (no pre-cursor signal) to 66% TW (+Point data) over two operating cycles. Subsequent destructive examination of the tube showed that the local maximum depth was 99% TW. This flaw was pressure-tested in the laboratory to 7000 psi without evidence of leakage, but was not taken to burst in order to preserve the specimen for chemical analyses of the tube surface and crack faces. It is noted that 7000 psi provides a large margin to the performance requirement of 3xNOP.

   Based on the Seabrook data, there is a small risk of progressing from NDD to a potential leakage condition within a 36-month inspection interval, considering the variables that may influence corrosion initiation and subsequent growth. For this reason, it is prudent that the tubes be examined to identify potential high stress conditions, so that an informed judgment can be made regarding the risks, options for cycle length, and potential corrective actions.

   This recommendation is based on engineering judgment since no data to correlate tubing material stress/strain condition to bobbin voltage response are available.

C. For plants with individual SG inspection intervals greater than 36 months, screening of the tubes to identify "signature tubes" is recommended. If "signature tubes" are identified, they should be removed from service or the inspection interval should be adjusted to 36 months or less. This recommendation is similarly based on the engineering judgment that the current risks of extended operation with "signature tubes" outweigh the costs of performing the evaluation and possibly removing a small number of tubes from service. Note that if additional data become available that permit correlation of bobbin response with tube material condition, tubes that were removed from service may be recovered at a later date.

   Experience has shown that the degree of scatter among the tubes of any or all bundles can be minimized by careful attention to the process. For example, if different analysts evaluate the tubes in a single plant or SG, measurement locations and techniques must be the same; the data from different calibration groups must be normalized to a common basis, etc. Outlier points are frequently the result of a process error and can be resolved by reexamination.

Plants with Alloy 600TT Tubing Manufactured by Westinghouse

Table 1 summarizes the operating plants with SGs with Alloy 600TT tubes that were manufactured at the Westinghouse Blairsville facility and the timeframes in which the tube bundles for each plant were manufactured.

Future Development

In an effort to refine this guidance, it is requested that utilities provide the results of their screening evaluation and the inspection results to EPRI. This plant experience can then be considered in refinement and potential relaxation of this guidance.

Sincerely,

Lawrence F. Womack
Vice President, Nuclear Services-Diablo Canyon Power Plant
Chair, SGMP Senior Representatives

Attachments

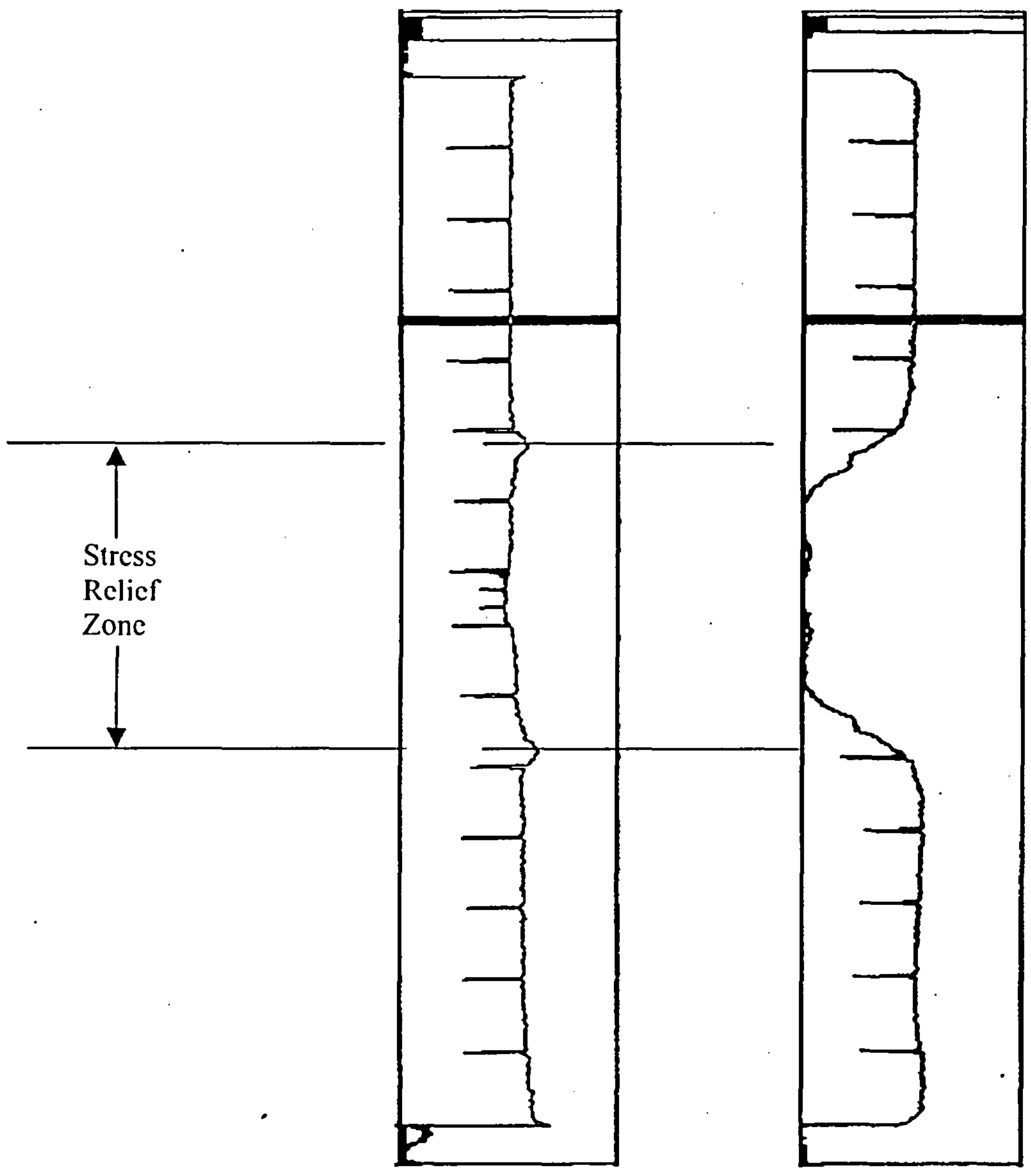
cc Jim Riley – NEI
Jeff Ewin – INPO
David Steininger – EPRI
Mohamad Behravesh – EPRI

Table 1

Plants with Alloy 600TT Tubing Manufactured at Westinghouse/Blairsville

SG Model	Plant	Manufacturing Timeframe	Notes
44F	Turkey Point 3	January-March 1979	All tubes are thermally treated Rows 1 through 8 are stress relieved in the u-bend
	Turkey Point 4	October 1978-January 1979	
	Point Beach 1	January-May 1983	
	H.B.Robinson	June-August 1983	
51F	Surry 1	March-May 1978	
	Surry 2	January-March 1978	
D5	Braidwood 2	February-April 1980	All tubes are thermally treated Rows 1 through 9 are stress relieved in the u-bend
	Byron 2	June 1978 – June 1979	
	Catawba 2	June 1978-May 1979	
	Comanche Peak 2	June 1978- October 1979	
F	Callaway	June-September 1977	Only Rows 1-10 are thermally treated and stress relieved
	Wolf Creek	August-October 1978	All tubes are thermally treated Rows 1 through 10 are stress relieved in the u-bend
	Seabrook	April-June 1980	
	Salem 1	October 1980-May 1981	
	Millstone 3	July-October 1980	
	Vogtle 1	October 1980-January 1981	
	Vogtle 2	October 1980-July 1981	
	Vandellos 2	January 1980-September 1982	
	Kori 2	April-August 1979	
	Kori 3	August-October 1980	
	Kori 4	October 1980-May 1981	
	Maanshan 1	August-October 1979	
	Maanshan 2	May-July 1980	
	Yeonggwang 1	September 1981-January 1981	
	Yeonggwang 2	June-October 1982	

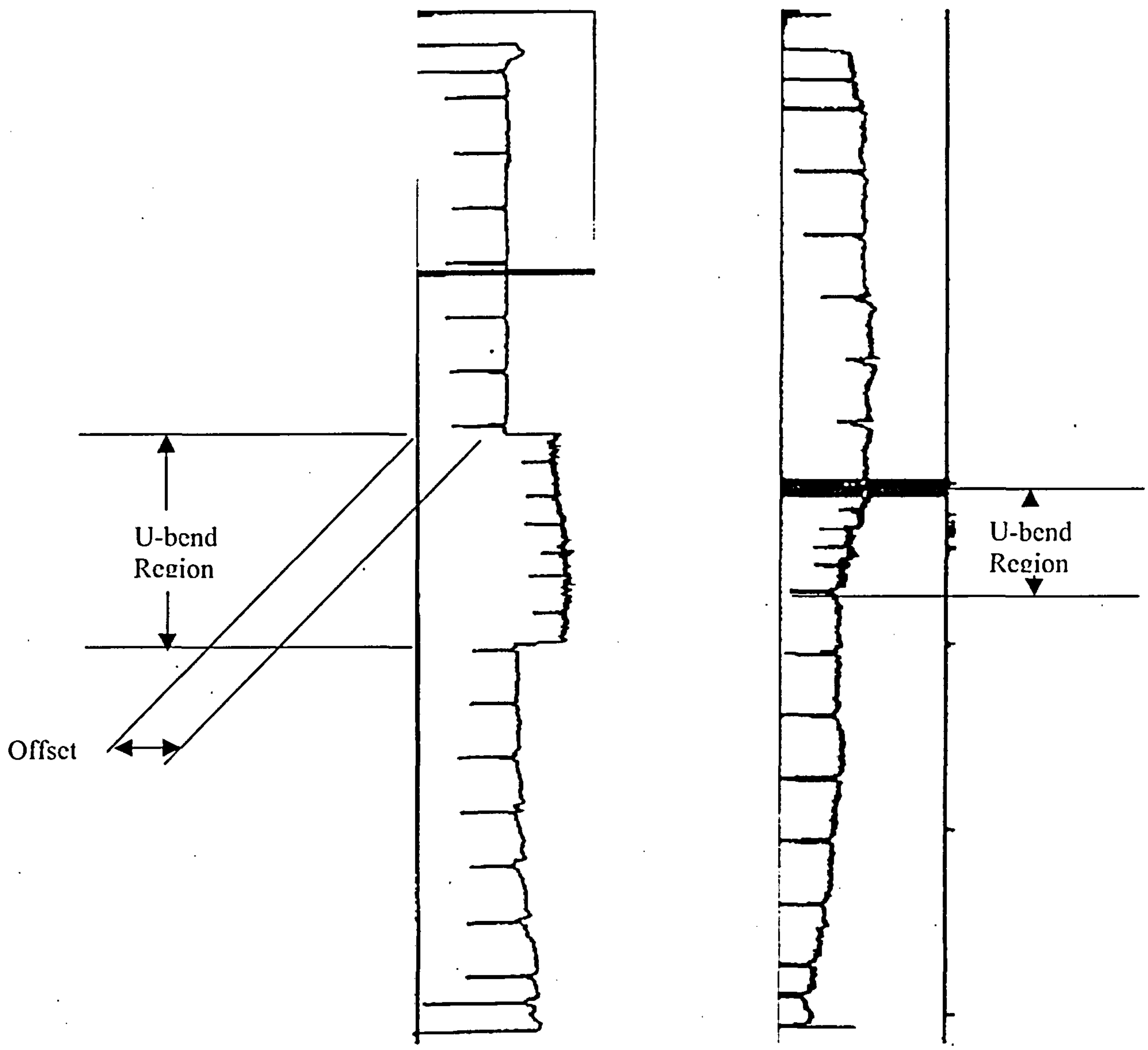
Figure 1
Bobbin Signal Characteristics for Short Row Tubes



a) Normal

b) Elevated Residual Stress

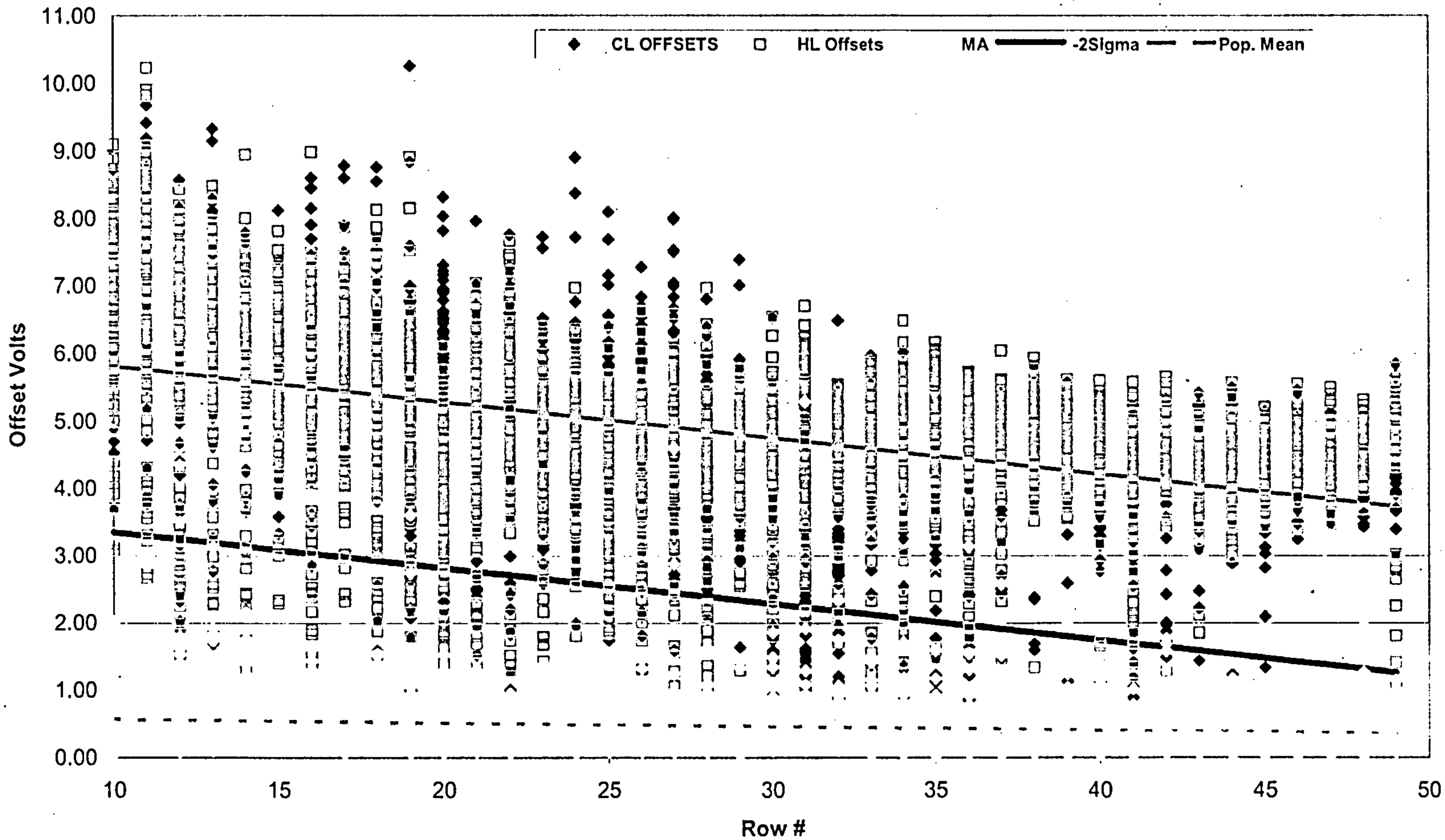
Figure 2
Bobbin Signal Characteristics for Long Row Tubes



a) Thermally Treated

b) Mill Annealed

Figure 3....Typical Result for Long-Row U-bend Offset Study Showing HL and CL Offset Measurements, Population Mean and Lower s-Sigma Bound and Comparison With Mill Annealed Population



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September 20, 2004

PMMP Utility Steering Committee
SGMP Technical Advisory Group (TAG)
NDE IRG

Subject: SGMP Information Letter on Automated Analysis

References:
1. EPRI PWR Steam Generator Examination Guidelines, Revision 6, 1003138
2. SGMP Interim Guidance for EPRI Steam Generator Examination Guidelines, Revision 6, Sections 6.2.4, 6.3.3.3, 6.5, and Appendix H, Supplements H1 and H2, from Larry Womack dated March 16, 2004
3. Institute of Nuclear Power Operations (INPO) Operating Experience Report (OE) 18651 dated May 2004

Dear SGMP Member:

The purpose of this letter is to communicate informational points to consider when utilizing automated analysis systems. This information contained should be evaluated upon receipt of this letter.

During the recent spring 2004 outage at Shearon Harris, it was discovered that portions of tubing were not analyzed by the automated analysis system used in the previous outage inspection. The incomplete coverage area was approximately ½" in length above the hot and cold leg top of tubesheet. The utility was using an automated analysis system to perform secondary party degradation analysis of full-length bobbin probe data. The utility and the inspection vendor commenced a root cause of the issue and performed extensive reviews of previous inspection parameters utilizing automated analysis. The vendor noted other plants were also affected by incomplete coverage with automated analysis systems during the past year. The incomplete coverage areas for these plants were small sections in the U-bend transition region.

The following are informational points to consider when utilizing automated analysis systems:

- Ensure program provides for oversight of vendor documents including automated analysis setup parameters.

- Consider having the automated analysis parameters, including revisions, independently reviewed and documented by experienced personnel. Items to consider during this review are:
    - The area of interest is covered by the automated software (i.e., the intended length of the tube is being analyzed).
    - The expected degradation is being addressed by the automated analysis parameters.
    - Re-analysis requirements, when revisions are made.

- When possible, for cases where the site-specific performance demonstration does not have sufficient site-specific data to adequately verify the sorts, consider running the automated analysis parameters on site-specific validation tubes with various defects or signals to ensure adequate coverage of the areas of interest. The "indication superpositioning" software, when available, will be a valuable tool to insert indications.

- Strengthen the controls, periodic checks, and documentation/record retention requirements when utilizing auto analysis systems.

Sincerely,

Lawrence F. Womack
Vice President, Nuclear Services-Diablo Canyon Power Plant
Chair, SGMP Senior Representatives

Attachments

cc Jim Riley – NEI
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David Steininger – EPRI
Mohamad Behravesh – EPRI

ELECTRIFY THE WORLD

Date: March 4, 2005

To: SGMP Technical Advisory Group (TAG)
PMMP Executive Committee
IIG
TSS
NDE IRG
E&R IRG

Subject: SGMP Information Letter, SGMP-IL-05-01, *Catawba Unit 2 Tubesheet Degradation Issues*

References:

1. The EPRI PWR Steam Generator Examination Guidelines, Revision 6, Report Number 1003138.
2. The EPRI Steam Generator Integrity Assessment Guidelines, Revision 1, Report Number 107621.
3. NEI 97-06, Revision 1.
4. EPRI 1009801 - MRP 111, "Resistance to Primary Water Stress Corrosion Cracking of Alloys 690, 52, and 152 in Pressurized Water Reactors" March 2004.
5. NEI APC Letter, "Steam Generator Tube Inspection Generic Letter (GL 2004-01) Response" October 15, 2004.

During the recent EOC13 outage at Catawba Unit 2, several tubesheet degradation issues were identified. The purpose of this information letter is to communicate the circumstances of this event and the information known to date about the potential cause of the degradation so that other utilities may make informed decisions concerning their steam generator programs. Please distribute this document internally within your organization among those who may have a need for this information.

Background
Catawba Unit 2 has Westinghouse Model D-5 steam generators with Alloy 600TT tubing. These steam generators have hydraulic full-depth tubesheet expansions with a mechanical (hard roll) tack expansion at the tube end. The purpose of the tack expansion was to hold the tube in place for installation of the tube-end to tubesheet clad autogenous weld prior to the full depth expansion. At the time of the inspection, Catawba Unit 2 had been operating for 14.7 EFPY at 615° F T-hot. The Catawba Unit 2 tubesheets are 21 inches thick with 0.15 inch of clad material. The tube ends are flush with the cladding.

During EOC13, circumferential indications were found in Tube 4-61 in the "B" steam generator. The location was 7.6 inches below the top-of-tubesheet on the hot leg. The indications were from the inside diameter of the tube. There were three indications; two were 180 degrees apart in the same axial plane and the third was in a different axial plane but inline with one of the other

two indications. They were all about 0.25 inches long and 30 degrees in circumferential extent. The Plus Point voltages were 0.4, 1.0 and 1.4 volts. There were also linear scratches identified at the location of the circumferential indications. The indications were identified by the Plus Point coil and confirmed by the 0.115 inch pancake coil. 0.080 high frequency pancake coil and the RG 3/4 probe.

In 1990, the bobbin coil detected three over-expansions at the same location. The over-expansions were 2, 2.5 and 3 mils. The eddy current data indicates they were located at the tube-end-hot plus 9.81, 11.58 and 13.24 inches and were 11.52 and 12.72 and 12.23 volts respectively as called on the 400 kHz differential channel. In 1990 the minimum identified voltage was 10 volts. The axial positions of the over-expansions are uncertain. The voltage normalization was to 1990 standards.

There are 584 tubes with over-expansions in the "A" steam generator, 247 tubes with over-expansions in the B" steam generator, 171 tubes in the "C" steam generator and 345 in the "D" steam generator. These over-expansions were identified by the bobbin probe in previous inspections. The tubes were hydraulically expanded into the tubesheet in a one step process. The over-expansions are associated with drilling problems in the tubesheet.

The identified over-expansions were inspected the full length of the tubesheet. As a result of that inspection, indications were found in the tube-ends and tack expansions. The inspection was expanded to 100 % in the "B" steam generator and 20 % in the "A", "C", and "D" steam generators. That inspection started out full-length of the tubesheet and was changed to the bottom two inches for inspection of the tack expansions.

There were 9 tubes with indications in the tack expansion and 188 tubes with tube-end weld indications in the "B" steam generator. Six of the 188 tubes had indications extending into the tubing material. There was also a tube with an indication in the tube-end in the "A" steam generator. There were no tubes with indications in the tube-end in the "C" steam generator and 7 in the "D" steam generator.

<u>Points to Consider</u>
The cornerstone of the Steam Generator Program as defined in Reference 3 is the Degradation Assessment (DA). The requirements associated with the DA are outlined in References 1 and 2. The DA is the key document in planning for the SG inspection, where inspection plans and related actions are determined, documented, and communicated prior to the outage. Important inputs to the DA include plant design information and other utility experiences. The recent degradation within the tubesheet at Catawba Unit 2 may be key input for utilities to consider in development of their DA. Utilities should assess the design conditions within their steam generators in planning their steam generator inspection. The Catawba Unit 2 stress conditions included:

- Over-expansions (bulges) within the tubesheet
- Mechanical roll tack expansions
- Tube-to-tubesheet seal welds

Primary water stress corrosion cracking (PWSCC) in Alloy 600MA tubing has historically occurred in areas of increased residual stress. Although Alloy 600TT tubing has increased resistance to stress corrosion cracking, degradation has occurred at expansion transitions in non-US plants and at TSP's in US plants. The Catawba Unit 2 experience indicates that degradation may occur in the tubesheet region of steam generators with 600TT tubing and the tubesheet expansion transition may not provide early warning of PWSCC in other areas of the tubesheet.

Conclusion/Recommendation

This letter is provided for information only and no specific action is required. Its purpose is to remind utilities to consider how they define over-expansions and whether PWSCC in over-expansions or tack roll expansions is a potential degradation mechanism that should be included in their Degradation Assessment. It should be noted that industry data proves that this issue does not apply to Alloy 690TT tubing (Reference 4).

One approach to employ for ensuring compliance with performance criteria is to redefine the tube inspection length for supplemental examinations (e.g., Plus Point). Per the process described in NEI's APC Letter (Reference 5), the utility should evaluate the elements of inspection program in accordance with the NRC position in Generic Letter 2004-01, and disposition any differences within their 10CFR 50 Appendix B corrective action process, and determine if a licensing amendment request is necessary. If the response to 2004-01 is changed, it is recommended that the NRC be informed of the revision.

Tubesheet weld issues are being addressed by an E&R IRG ad hoc committee and information will be provided as it becomes available.

Sincerely,

Jeffrey T. Gasser

Jeffrey T. Gasser
Executive Vice President and Chief Nuclear Officer, Southern Nuclear
Chair, PMMP Executive Committee

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Mohamad Behravesh – EPRI

ELECTRIC POWER RESEARCH INSTITUTE

Date: **March 13, 2006**

To: SGMP Technical Advisory Group
PMMP Executive Committee

Subject: **SGMP-IL-06-01**, Information Letter Regarding:
TSTF-449-Normal Operating Leakage LCO vs. Accident Analyses Assumptions

Purpose:

The purpose of this letter is to inform licensees of a licensing basis condition that may require modification of the wording in the model application, significant hazards analysis and technical specification bases provided as a template for adoption of TSTF-449[1]. The condition is only applicable if the primary to secondary leakage value assumed in the accident analyses has been reduced.

TSTF-449[1] - Normal Operating Leakage LCO vs. Accident Analyses Assumptions

Some licensees may have reduced the primary to secondary leakage assumed in their accident analyses due to control room habitability or other issues. Such a reduction may conflict with the approach presented in TSTF-449 and result in a NRC request for additional information (RAI). Specifically, TSTF-449 requires the normal operating LCO to be reduced to 150 gpd/SG, and assumes that the accident analysis assumption remains unchanged (typically a value of 0.5 gpm/SG or 500 gpd/SG). TSTF-449 bases discuss this in the following context:

> "The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analysis."

Further, NRC's model SER for TSTF-449, Steam Generator Tube Integrity recognizes this reduction in the normal operating LCO stating:

> **"[Note to reviewers: The following section, 3.6.X, is needed only for those plants which currently have a higher than 150 gpd limit per SG. Such plants should be proposing to change this limit to 150 gpd.]**

[1] Technical Specification Task Force, Improved Standard Technical Specifications Change Traveler TSTF-449, Revision 4, Steam Generator Tube Integrity

> [3.6.X Revision of Leakage Limit for Individual SGs.
> LCO 3.4.13.e (which will become LCO 3.4.13.d, as discussed above) currently specifies a [500] gpd limit for primary to secondary LEAKAGE through any one SG. The proposed specification would replace this limit with a more restrictive 150 gpd limit. Although no leakage limit, even if reduced to zero, can be totally effective in preventing SG tube ruptures, the NRC staff notes that operating experience demonstrates that leakage limits are an important element of an overall approach to limiting the occurrence of tube rupture and for ensuring SG tube integrity. In addition, the proposed limit is [significantly less than the conditions assumed in the safety analyses.] For these reasons, the NRC staff finds the revised LCO limit to be more restrictive than the existing limit, to be in accordance with 10 CFR 50.36(c)(2)(ii) and, thus, acceptable.]"

If primary to secondary leakage assumed in your accident analyses has been reduced from the typical value, the NRC considers this as a reduction in margin. Further, this reduction in margin is considered more critically for plants that have leakage predictions in their licensing basis due to alternate repair criteria (e.g., allowing cracks in certain regions to remain inservice) or installed leak limiting sleeves.

Interaction between the NRC and some licensees indicate that a potential solution for restoring margin to the accident analysis assumption is to further reduce the normal operating LCO below 150 gpd/SG or place additional controls on plant operation through the operating procedures. The controls would limit normal operating leakage through any one steam generator to half of the value assumed in the accident analysis less the amount of postulated leakage predicted in the Operational Assessment that is completed following each inspection. Postulated leakage may include leakage from the tubesheet region if an alternate repair criterion is in use, or from leak limiting sleeves and other sources as identified in the Operational Assessment. Existing plant procedures should already incorporate the guidance of the EPRI PWR Primary To Secondary Leak Guidelines, which provide shutdown requirement of 75 gpd/SG. Therefore, if the current margin (e.g., the amount taking the value assumed in the accident analysis less postulated leakage) is less than a factor of two times 75 gpd through any one steam generator, the plant procedure or LCO could be revised to limit normal operating leakage to the lower value for the subsequent operating period. For Example:

(PLANT) Steam Generators Leakage and Margin Assessment for Cycle XX			
		SG 2A	SG 2B
Define Total Predicted Leakage	Tubesheet Leakage Prediction	50 gpd	50 gpd
	Sleeve Leakage Prediction	20 gpd	30 gpd
	Other Leakage Prediction	15 gpd	30 gpd
	Total Predicted Leakage	**85 gpd**	**110 gpd**
Margin Assessment	Leakage Assumed in Accident Analyses	200 gpd	200 gpd
	Total Predicted Leakage	85 gpd	110 gpd
	Current Margin	115 gpd*	90 gpd*
	Plant Procedure Shutdown Criterion (or LCO)	75 gpd	75 gpd
* If **Current Margin** is less than a factor of 2 times the **Plant Procedure Shutdown Criterion**, reduce the **Plant Procedure Shutdown Criterion** to one-half of the **Current Margin** Value for the next Cycle.			

In the example provided in the table, the **Plant Procedure Shutdown Criterion** should be reduced to 57.5 gpd for SG 2A and 45 gpd for SG 2B.

Licensees should note that this approach does not guarantee that a reduction in the normal operating LCO will not be required by the NRC, nor does it guarantee that the NRC will view the margin available to the accident analyses assumption as adequate. In addition, Licensees may also need to address the potential for normal operational leakage to increase under higher accident pressures, and the potential for such an increase to result in exceeding the accident limits.

Sincerely,

Jeffrey T. Gasser

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