Risk Informed Inspection for Steam Generators

Volume 1: Deterministic Performance Based Criteria

Technical Report

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Risk Informed Inspection for Steam Generators

Volume 1: Deterministic Performance Based Criteria

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REPORT SUMMARY

Basing a steam generator (S/G) inspection program on meeting structural and leakage performance criteria will ensure adequate safety margins and may reduce inspection costs and personnel radiation exposure. This report provides evaluation procedures for defining S/G inspection intervals using performance based criteria. Implementation of these procedures will allow utilities to develop a tube inspection program tailored to specific S/G conditions. For many plants with second generation S/Gs, this could mean significant cost savings by reducing the number of inspections needed over the life of the plant.

Background

Up until several years ago, first generation S/Gs were original equipment in PWR plants. Service experience has shown that many tubes in first generation S/Gs have had significant in-service degradation from wear and various corrosion mechanisms. Second generation S/Gs—which have been designed to reduce in-service tube degradation—are being used as original equipment for newer plants and as replacements for plants with first generation S/Gs. Inspection criteria currently used by the industry includes: 1) inspection of each S/G no less than every two fuel cycles, 2) inspection of all tubes in all S/Gs within a rolling 60 effective full power month time frame, and 3) inspection of a minimum of 20% of the total tube population during each planned inspection. Available service experience from U.S. PWR plants indicates that second generation S/Gs have significantly less tube degradation compared to first generation S/Gs. Because of this relatively low degradation, there is the potential for reducing the frequency and number of tube inspections for second generation S/Gs while maintaining adequate tube structural and leakage integrity. Previous EPRI work has indicated that inspection intervals could be increased for many second generation S/Gs beyond those allowed in current plant technical specifications and in Section 3 of EPRI's PWR Steam Generator Examination Guidelines (report TR-107569-V1R5).

Objective

To develop a method that would allow S/G inspection intervals to be defined based on the maximum expected time for maintaining acceptable structural and leakage performance criteria.

Approach

The foundation for the performance based inspection (PBI) method described in this report is identification of the maximum operating interval where the degradation in any one tube does not exceed the degradation allowed by deterministic structural and leakage performance criteria. Determination of the inspection interval can be based on either service experience, analytical predictions, or a combination of service experience and analytical predictions. The project team defined three approaches for using available information to develop PBI programs and define inspection intervals—1) lead plant approach, 2) analytical model approach, and 3) plant-specific data approach. These approaches can be used in conjunction with EPRI's Steam Generator Tube

Integrity Assessment Guidelines (TR-107621-V1) to define an inspection interval that ensures compliance with structural and leakage performance criteria.

Results

The method and evaluation procedures in this report provide a technically sound, well-defined process for developing PBI programs that comply with structural and leakage performance criteria. Implementation of a PBI program ensures adequate safety margins and could reduce inspection costs and personnel radiation exposure. Such a program may significantly increase the inspection interval for many second generation S/Gs, compared to the prescriptive intervals defined in current plant technical specifications and Section 3 of EPRI's PWR Steam Generator Examination Guidelines. PBI programs will provide the greatest benefit when they are implemented long before initiation of significant wear or corrosion degradation. To further assist utilities, Volume 2 of this report will address risk-based inspection criteria.

EPRI Perspective

Current industry inspection practice is to use prescriptive methods to define inspection intervals for S/G tubes. This practice has worked exceptionally well to ensure that tube performance criteria is met for both first and second generation S/Gs. However, such methods may be unnecessarily burdensome for second generation S/Gs which, due to their improved materials and designs, may not experience active tube degradation for several years to come. The use of PBI criteria allows the inspection program to be tailored to specific S/Gs. Many plants with second generation S/Gs and no active tube degradation can benefit by increasing inspection intervals beyond those required by either plant technical specifications or other prescriptive criteria. The cost savings from increasing inspection intervals would equal the normal costs incurred in performing an inspection multiplied by the number of currently planned inspections that can be deferred over the life of the S/G. Implementation of a PBI program, as described in this document, may require the utility to obtain approval to deviate from current plant technical specification requirements.

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Keywords

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Risk-informed in-service inspection
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ABSTRACT

This report presents the methodology and evaluation procedures to develop performance based inspection intervals for steam generators. Implementing a performance based methodology to define inspection intervals allows inspection intervals to be based on the time that acceptable tube structural and leakage performance criteria are maintained, rather than the prescriptive inspection intervals specified in current plant Technical Specifications and Chapter 3 of the *PWR Steam Generator Examination Guidelines,* EPRI TR-107569-V1R5. An inspection program based on meeting structural and leakage performance criteria ensures adequate safety margins are maintained and, at the same time, reduces inspection costs and personnel radiation exposure.

The performance based inspection methodology will provide the greatest benefit when applied to second (2nd) generation S/Gs, which have been designed to reduce inservice degradation. The 2nd generation S/Gs are being used as original equipment for newer plants, and as replacements for plants with severely degraded older S/Gs.

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1 INTRODUCTION

1.1 Background

First (1st) generation steam generators (S/Gs) are S/Gs that have any one of the following conditions: mill annealed (MA) alloy 600 tubes, carbon steel tube support plates with drilled holes, or tubes that were either explosively expanded or hard rolled into the tube sheet. Up until several years ago, 1st generation S/Gs were original equipment in pressurized water reactors (PWRs). Service experience shows that many tubes in first 1st generation S/Gs have significant inservice degradation from wear and various corrosion mechanisms. This degradation has resulted in increased numbers of tube inspections and the repair of substantial numbers of degraded tubes. At many plants the number of degraded tubes removed from service in 1st generation S/Gs was large enough that the S/Gs were replaced or will be replaced over the next several years.

Second (2nd) generation S/Gs have been designed to reduce inservice degradation. The design changes include use of: tube materials and thermal treatments that enhance tube corrosion resistance, stainless steel supports and support configurations that reduce the potential for corrosion of tubes at tube supports, and improved tube expansion methods that reduce the potential for corrosion of tubes at the tube sheet. Specifically, S/Gs are categorized as 2nd generation S/Gs when they have thermally treated (TT) alloy 600 or 690 tubes, stainless steel tube supports with quatrefoil, lattice bar or egg crate configurations, and tubes that are hydraulically expanded into the tube sheet. The 2nd generation S/Gs are being used as original equipment for newer plants, and as replacements for plants with 1st generation S/Gs.

Available service experience at PWRs in the United States indicates that 2nd generation S/Gs have significantly less tube degradation compared to 1st generation S/Gs. To date, the only significant degradation detected in 2nd generation S/Gs is wear, which has occurred in some 2nd generation S/Gs. Some 2nd generation S/Gs have operated over ten effective full power years (EFPY) without tube degradation.

Because the degradation in 2nd generation S/Gs is relatively low there is the potential to reduce the frequency and number of tube inspections for 2nd generation S/Gs and still maintain adequate structural and leakage integrity. The results from a previously performed scoping study [1] indicate inspection intervals could be increased for 2nd generation S/Gs compared to requirements in current plant Technical Specifications (T/S) and Chapter 3 of the PRW Steam Generator Examination Guidelines (ISI Guidelines) [2].

1.2 Objectives

The purpose of the work described in this report is to define a methodology that would allow inspection intervals to be defined based on performance. Implementing a performance based methodology to define inspection intervals would allow inspection intervals to be based on the time that acceptable structural and leakage performance criteria are maintained, and would eliminate the application of the prescriptive inspection intervals specified in the current T/S and ISI Guidelines [2]. Implementing an inspection program based on meeting structural and leakage performance criteria would ensure adequate safety margins are maintained and, at the same time, reduce inspection costs and personnel radiation exposure.

1.3 Approach

The approach is based on determining the maximum operating interval where the degradation in any one tube does not exceed the degradation level allowed by application of deterministic structural and leakage performance criteria. Determination of the inspection interval can be based on either service experience, analytical predictions, or combinations of service experience and analytical predictions. The deterministic performance criteria have been defined in previously developed industry guidelines [3]. Inspection programs using inspection intervals determined using the deterministic performance criteria are designated as performance based inspection (PBI) programs.

1.4 Implementation

Implementation of this approach will have its greatest benefit for S/Gs with relatively low levels of degradation. Consequently, the work described in this report focuses on 2nd generation S/Gs. Service experience for 2nd generation S/Gs indicates some S/Gs can operate for relatively long times with no wear degradation while other S/Gs develop wear degradation after relatively short operating periods. Typically, S/Gs with early wear degradation exhibit initial, relatively rapid wear rates followed by significantly slower wear rates. PBI programs will be effective when they are implemented for times: prior to initiation of significant wear degradation, during periods of low wear rates and prior to initiation of significant corrosion degradation. Should degradation become extensive then risk-based performance criteria can be implemented to define the maximum inspection interval and ensure adequate structural and leakage integrity is maintained during operation.

An important compliment to implementation of a PBI program is the use of in-situ pressure testing. In-situ pressure testing can be employed when the inspection results indicate the degradation is outside the limits allowed by the performance criteria. In this instance, in-situ pressure tests are performed to determine whether the structural and leakage performance criteria are met.

Periodic inspection programs generally are not effective for monitoring degradation from random events such as loose parts. Consequently, a program to reduce the likelihood of loose parts entering the S/G and to detect the presence of loose parts becomes increasing important for implementation of a PBI program.

Section 2 of this report is a summary of the methodology used to determine inspection intervals for PBI programs. Guidelines for developing PBI programs are presented in Section 3, while an example case study using these guidelines is described in Section 4. Conclusions and recommendations are listed in Section 5. A glossary and list of acronyms are contained in Sections 6 and 7, respectively.

Appendix A presents a brief summary of tube repair in 1st and 2nd generation S/Gs. Appendix B provides a summary of the EPRI analytical methodology to predict AVB wear, and a list of the input needed for the AVB wear analysis. Appendix C provides guidelines for predicting the time to reach corrosion degradation.

2
SUMMARY OF INSPECTION INTERVAL DETERMINATION

The determination of inspection interval is based on the operating time where the degradation in any one tube does not exceed the degradation allowed by the deterministic structural and leakage performance criteria. This determination involves two steps. The first step defines a degradation specific nondestructive examination (NDE) measurement parameter and the value of this parameter that demonstrates compliance with the performance criteria. The second step involves predicting the operating time at which the degradation in any tube will be equal to the value of the NDE measurement parameter corresponding to the performance criteria. The remainder of this section describes the performance criteria and the approaches that can be used to determine the inspection interval and ensure compliance with the performance criteria.

2.1 Deterministic Performance Criteria

The performance criteria used to ensure adequate structural and leakage integrity have been defined previously [3] and are:

2.1.1 Structural Integrity Performance Criterion

S/G tubing 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 margin of 3.0 against burst under normal full power operation and a margin of 1.4 against burst under the limiting design basis accident concurrent with a safe shutdown earthquake.

2.1.2 Accident-Induced Leakage Performance Criterion

The primary to secondary accident leakage rate for the limiting design basis accident, other than a steam generator tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all S/Gs and leakage rate for an individual steam generator. Leakage is not to exceed 1 gallon per minute (gpm) (3.79 liters per minute) per steam generator, except for specific types of degradation at specific locations where the tubes are confined, as approved by the Nuclear Regulatory Commission and enumerated in conjunction with the list of approved repair criteria in the Technical Requirements Manual (TRM).

2.1.3 Operational Leakage Performance Criterion

The reactor coolant system operational primary to secondary leakage through any one S/G shall be limited to 150 gallons per day (gpd) (568 liters per day).

2.2 Performance Criteria Measures

The performance criteria typically are translated into values of a NDE measurement parameter that can be used to assess compliance with the performance criteria. The NDE measurement parameter is degradation specific. Examples of degradation specific NDE measurement parameters include, percent through-wall (%TW) degradation for wall thinning, and voltage for outside diameter stress corrosion cracking (ODSCC) at tube support plates. The methods used to determine the values of NDE measurement parameters corresponding to the performance criteria are described in [4], and are illustrated in the case study in Section 4 of this report.

The value of the NDE measurement parameter corresponding to the margins against tube rupture specified by the structural performance criteria is defined as the structural limit (SL). The SL is determined from experimental or analytical relationships between burst pressure and the NDE measurement parameter for degraded tubes, and includes adjustments for uncertainty in the relationship and material properties. The SL is then adjusted for NDE measurement uncertainty; this adjusted value is defined as the condition monitoring limit (CML). The CML is the value of the NDE measurement parameter that is compared to the inspection results for each tube to determine if the structural performance criteria are met. These procedures are described in detail in [4], and are illustrated in Section 4 of this report.

There may be tubes where the value of the NDE measurement parameter for the degraded tube exceeds the CML. In this event, an in-situ pressure test can be performed to demonstrate compliance with the margins specified in the structural performance criteria.

Similar procedures are used to assess compliance with the performance criteria for leakage.

2.3 Determination of the Inspection Interval

The inspection interval is the time it takes degradation to grow from an initial degradation condition at the beginning of an operating interval (BOI) to the CML. Two initial degradation conditions at the BOI are considered.

In the first instance, no degradation has been detected prior to the BOI and degradation initiation and the time for the degradation to grow to the CML is predicted using analytical models or service experience from other plants with similar S/Gs.

When degradation has been detected in the S/G prior to the BOI, the inspection interval is determined from the time it takes to grow the degradation in tubes remaining in service at the BOI to the CML, or,

Inspection Interval = (CML – Degradation at BOI) / Degradation Growth Rate.

The inspection interval unit is time (e.g., EFPY), the CML and the degradation at BOC is the unit of the NDE measurement parameter (e.g., %TW), and the degradation growth rate unit is the unit of the NDE measurement parameter per unit time (e.g., %TW per EFPY).

Generally, the degradation and degradation growth rate in S/G tubes are distributions of values. Several alternative methods can be used to evaluate these distributions and determine the inspection interval [4]. One alternative is use of a deterministic evaluation procedure where the degradation at the BOI is the maximum degradation in any tube remaining in service, and the growth rate is the maximum value determined from the inspection results from two or more successive operating cycles. As an alternative to the maximum growth rate, the 95 percentile growth rate can be used provided there are adequate data.

Another alternative is to use a sampling evaluation procedure where the degradation at BOI and the growth rate during the operating interval are distributions. In this instance, Monte Carlo sampling techniques typically are used to determine a distribution of degradation at the end of the interval. The EPRI software STEIN [5] can be used to perform the Monte Carlo sampling and predict the number of degraded tubes as a function of values of the NDE parameter at the end of any specified operating interval. A trial and error procedure can be used to determine the maximum operating interval that would have the value of the NDE measurement parameter for the performance criteria equal the CML.

Because the degradation predicted by STEIN is distributed, there will be fractions of tubes in the distribution tail. In this instance, the tail of the degradation distribution at the end of the operating interval (EOI) is integrated back from the maximum value of the NDE measurement parameter in the distribution until the sum of the fractional tubes is equal to one. The value of the NDE measurement parameter where the sum of the fraction of tubes is equal to one is the value compared to the CML to assess compliance with the performance criteria.

The next section describes various approaches that may be used to predict degradation initiation and growth rate depending on the degradation history of the S/Gs.

2.4 Approaches for Inspection Interval Determination

The inspection interval is determined from the operating time at which the maximum value of the NDE measurement parameter in any tube reaches the CML. The length of the inspection interval is degradation specific and depends on the degradation condition at the BOI and the degradation growth rate during operation. The degradation mechanisms considered are wear and various corrosion mechanisms. The inspection interval is the shorter of the times predicted to reach the CML for corrosion and wear degradation.

The remainder of this section describes three possible approaches for determining degradation growth and the inspection interval. Selection of an approach is S/G specific and depends on the degradation experience for the S/Gs; often, more than one approach may be used at a plant. The next three sections present tables of data for plant conditions related to S/G model, operating time, number of tubes repaired due to AVB wear, and other plant conditions that may be of interest in defining approaches for determining inspection intervals. These data were obtained from the EPRI Steam Generator Degradation Database that was current as of May 1999 [6].

2.4.1 Lead Plant Approach

The lead plant approach is applicable for plants where there is little or no tube degradation and there exists plants with "similar" S/Gs with longer operating time. The plant (i.e., S/G) with the shorter operating time and little or no S/G tube degradation is the trailing plant, and plant(s) with "similar" S/Gs and longer operating times is the lead plant. A trailing plant will use the experience from a lead plant(s) to define their inspection interval. A lead plant may or may not have degraded S/G tubes.

To use this approach an assessment must be made to determine if the lead plant will provide an accurate prediction of the degradation condition at the trailing plant. The degradation mechanisms considered in this assessment are wear and various corrosion mechanisms, and different assessments are made to determine the similarities between lead and trailing plants.

For wear an assessment is made to establish thermal hydraulic (T/H) and structural similarity between the S/Gs in the trailing and lead plants. This document will refer to the EPRI T/H and Wear Model [7] for the assessment of wear in the trailing plant and the candidate lead plants. Other wear models may also be considered for this purpose. For corrosion, the assessment is made based on design, tube material and heat treatment, operating temperature, tube expansion process, and other conditions that may effect corrosion degradation. The results from these evaluations will identify the plants that can be lead plants for the trailing plant. Appendices B and C provide information needed to perform the similarity assessment for AVB wear and corrosion, respectively, of trailing and lead plants.

Once the trailing plant and appropriate lead plant(s) have been determined, the inspection interval for the trailing plant can be determined in one of the following two ways depending on the tube degradation level in the lead plant(s).

The first case assumes that the lead plant(s) has no degradation. In this instance, the inspection interval for the trailing plant can be defined by the maximum operating time of the lead plant(s). The second case assumes that the lead plant(s) has degradation. In this situation, the inspection interval for the trailing plant is defined by an evaluation of the S/G tube degradation in the lead plant as described in Section 2.3. This evaluation uses the degradation history and growth rates to predict the time for degradation initiation in the trailing plant and the time it takes to grow the degradation to a level corresponding to the CML.

Table 2-1 lists combinations of plants that have the potential to be trailing and lead plants for defining inspection intervals for 2nd generation S/Gs. The classification in Table 2-1 is based on wear at anti-vibration bars (AVBs) and is provided as an example only. Other plants that are not listed may also be able to be categorized as trailing and/or lead plants.

Lead and trailing plants also can be identified for corrosion degradation based on similar design and operational conditions (e.g., 2nd generation S/Gs with alloy 600 thermally treated (600 TT) tubes and the same temperature at the inlet to the hot leg piping). For example, a review of the information in Table 2-1 indicates that Vogtle 1 and Wolf Creek can be lead plants for corrosion degradation for Seabrook, and Vogtle 2. Similarly, Surry 1 and 2 can be lead plants for Salem 1.

Table 2-1
Classification by S/G Model of Candidate Lead and Trailing Plants for AVB Wear in US 2nd Generation S/Gs—(Example Only)

Plant	S/G Type	S/G Model	No. S/Gs	Net MWe	Hot Leg Temp (°F)	Tube Material	EFPY	Cumulative No. of Repaired Tubes Due to AVB Wear
INDIAN PT 3	REPL	W-44F	4	965	597	690 TT	5.7	0
ROBINSON	REPL	W-44F	3	700	604	600 TT	8.5	0
TURKEY PT 4	REPL	W-44F	3	666	599	600 TT	9.1	0
POINT BEACH 1	REPL	W-44F	2	485	597	600 TT	9.8	5
TURKEY PT 3	REPL	W-44F	3	666	599	600 TT	11.4	39
SURRY 2	REPL	W-51F	3	788	605	600 TT	12.5	8
SURRY 1	REPL	W-51F	3	788	605	600 TT	12.7	7
NORTH ANNA 2	REPL	W-54F	3	897	613	690 TT	2.6	0
NORTH ANNA 1	REPL	W-54F	3	893	613	690 TT	5.0	0
COOK 2	REPL	W-54F	4	1060	606	690 TT	5.8	0
SALEM 1	REPL	W-F	4	1090	602	600 TT	0.7	0
SEABROOK	ORIG	W-F	4	1148	618	600 TT	5.9	24
VOGTLE 2	ORIG	W-F	4	1157	618	600 TT	6.3	9
MILLSTONE 3	ORIG	W-F	4	1150	621	600 TT	6.9	30
VOGTLE 1	ORIG	W-F	4	1157	618	600 TT	8.8	34
WOLF CREEK	ORIG	W-F	4	1150	618	600 TT	9.7	91

For convenience in identifying lead and trailing plants for AVB wear, Table 2-1 lists the plants for each S/G model in ascending order of EFPY. Within any S/G model category any plant can be a lead plant for other plants with less operating time, provided similar S/G conditions are demonstrated for the trailing and candidate lead plant.

In the event that similarity in wear or corrosion characteristics cannot be demonstrated for a trailing plant and candidate lead plant(s) then the analytical model approach described in the next section can be used to determine the inspection interval.

2.4.2 Analytical Model Approach

The analytical model approach can be used for any S/G but is described here for the case where there is little or no S/G degradation and where plants with "similar" S/Gs do not have longer operating times.

Two options are described for the analytical approach. In the first option, plants with S/Gs that have similar wear and corrosion conditions are grouped so that they can implement an integrated inspection program. This integrated program will allow inspections to be performed on a rotating basis to monitor and confirm the degradation predictions and assess compliance with the performance criteria. Because the integrated program uses rotating inspections it provides a means to validate the analytical predictions and provides the opportunity to increase the inspection interval for plants in the group compared to a single plant. The inspection interval is determined by the results from the wear and corrosion evaluations, and is the shorter of the times to reach the CML from either wear or corrosion degradation.

To use this option an assessment must be made to determine if the S/Gs in all the plants in the group have similar degradation mechanisms and degradation rates. The degradation mechanisms considered in this assessment are wear and various corrosion mechanisms.

For AVB wear an assessment is made to establish thermal hydraulic (T/H) and structural similarity between the S/Gs in the group of plants. This assessment uses the EPRI T/H and Wear Model [7] for the plants. Appendix B provides information needed to perform the similarity assessment for AVB wear. For corrosion the assessment is made based on design, tube material and heat treatment, operating temperature and other conditions that may effect corrosion degradation (for example, see Sections 2.4.1 and 2.4.3). The results from these evaluations will identify the plants that can be grouped for the purpose of a integrated inspection program.

The second option is applicable to a single plant. In this instance the AVB wear and corrosion models described in Appendices B and C are used to determine the time for the degradation level in the S/Gs to reach the CML. The inspection interval is the shorter of the times to reach the CML from either wear or corrosion degradation.

Table 2-2 lists the plants that have little or no degradation and little operating time, and are candidates for determining the inspection interval for 2nd generation S/Gs using analytical models for evaluation of AVB wear. Other plants that are not listed may also benefit by using analytical models to predict AVB wear.

Table 2-2
US Plants With 2nd Generation S/Gs That Are Candidates for Evaluation Using Analytical Models for AVB Wear—(Example Only)

Plant	S/G Type	S/G Model	No. S/Gs	Net MWe	Hot Leg Temp (°F)	Tube Material	EFPY	Cumulative No. Repaired Tubes Due to AVB Wear
ST. LUCIE 1	REPL	BWI	2	839	599	690 TT	0.0	0
BRAIDWOOD 1	REPL	BWI	4	1120	610	690-TT	0.0	0
BYRON 1	REPL	BWI	4	1120	613	690 TT	0.7	0
MC GUIRE 2	REPL	BWI	4	1129	618	690-TT	0.9	0
MC GUIRE 1	REPL	BWI	4	1129	618	690 TT	1.0	2
CATAWBA 1	REPL	BWI	4	1129	613	690 TT	1.1	0
GINNA	REPL	BWI	2	470	589	690 TT	1.5	0
MILLSTONE 2	REPL	BWI	2	870	596	690 TT	1.8	0
POINT BEACH 2 *	REPL	W-D47F	2	485	597	690 TT	0.9	0
SUMMER	REPL	W-D75	3	895	619	690 TT	1.0	0
STP 1	REPL	W-D94	4	1250	620	690 TT	0	0

2.4.3 Plant Specific Data Approach

This approach is applicable for S/Gs that have sufficient tube degradation experience to predict future degradation and determine the inspection intervals based on plant and S/G specific data. Table 2-3 lists the plants with 2nd generation S/Gs that have S/G specific data that can possibly be used to determine the inspection interval for AVB wear.

Because 2nd generation S/Gs currently do not have corrosion degradation, predictions of the time to corrosion degradation generally will have to be determined using the models described in Appendix C. However, lead plant data can possibly be used to predict tube corrosion degradation for S/Gs at other plants. For example, the information in Table 2-3 indicates that Vogtle 1 and Wolf Creek can be lead plants for corrosion degradation for Seabrook, Vogtle 2, and Comanche Peak 2.

Table 2-3
US Plants With 2nd Generation S/Gs That Have Sufficient S/G Specific Data to Determine the Inspection Interval For AVB Wear—(Example Only)

Plant	S/G Type	S/G Model	No. S/Gs	Net MWe	Hot Leg Temp (°F)	Tube Material	EFPY	Cumulative No. Repaired Tubes Due to AVB Wear
COMANCHE PK 2	ORIG	W-D5	4	1150	619	600 TT	3.5	5
BRAIDWOOD 2	ORIG	W-D5	4	1120	610	600 TT	7.1	77
BYRON 2	ORIG	W-D5	4	1120	609	600 TT	8.6	117
CATAWBA 2	ORIG	W-D5	4	1129	615	600 TT	9.3	27
POINT BEACH 1	REPL	W-44F	2	485	597	600 TT	9.8	5
TURKEY PT 3	REPL	W-44F	3	666	599	600 TT	11.4	39
SURRY 2	REPL	W-51F	3	788	605	600 TT	12.5	8
SURRY 1	REPL	W-51F	3	788	605	600 TT	12.7	7
SEABROOK	ORIG	W-F	4	1148	618	600 TT	5.9	24
VOGTLE 2	ORIG	W-F	4	1157	618	600 TT	6.3	9
MILLSTONE 3	ORIG	W-F	4	1150	621	600 TT	6.9	30
VOGTLE 1	ORIG	W-F	4	1157	618	600 TT	8.8	34
WOLF CREEK	ORIG	W-F	4	1150	618	600 TT	9.7	91

The availability of the three approaches provides the opportunity for all plants with 2nd generation S/Gs to implement inspection programs with performance based inspection intervals. For example, a lead plant (described in Section 2.4.1) may have degradation and can use their S/G specific degradation experience to determine the inspection interval. On the other hand if a lead plant does not have degradation, the analytical model approach (see Section 2.4.2) can be employed to predict corrosion and wear degradation and a corresponding inspection interval.

In addition, some plants have the opportunity to use more than one approach to determine the inspection interval. Application of more than one approach may be desired to increase the confidence in the predicted inspection interval. For example, plants that are evaluated using the S/G data specific approach also can use the analytical model approach to confirm that the degradation growth rates during future operation are consistent with the data from past operation.

Also, as described in Section 2.4.2 for the analytical model approach, plants with similar S/G conditions, short operating times and no degradation can implement a rotating inspection schedule where a different plant is inspected at successive outages to confirm the inspection interval predictions. This strategy provides a means to obtain a higher level of assurance that the performance criteria are met, and the potential to have even longer inspection intervals if degradation is not detected as the individual plants are inspected on a rotating basis.

3
PBI PROGRAM DEVELOPMENT AND IMPLEMENTATION

The procedure for development and implementation of a PBI program is illustrated in Figures 3-1 through 3-3. Figure 3-1 directs the user to the appropriate procedure for determining the inspection interval based on the service history of degradation in the S/Gs or the predicted time to wear and corrosion degradation. Figure 3-2 illustrates the procedure for defining the inspection interval and inspection scope when degradation was detected prior to implementation of the PBI program. Figure 3-3 illustrates the procedure for defining the inspection interval and inspection scope when no degradation was detected prior to implementation of the PBI program.

Figures 3-2 and 3-3 essentially outline the same procedure for defining the inspection scope and interval. The only difference is that a 100% inspection is required for the susceptible region when degradation has been detected prior to implementation of a PBI program. Alternatives to the 100% initial inspection of the susceptible region can be defined using available service data and accounting for uncertainty in the portion of the susceptible region that may not have been inspected prior to implementation of the PBI program.

The procedures shown in Figures 3-1 through 3-3 can be applied at any time during operation to define an inspection interval. This procedure allows plants to defer an inspection planned for the next outage in the event the plant started before there was time to evaluate implementation of a PBI program. Additionally, the potential for loose parts should be evaluated and determined to be acceptably low prior to implementing the PBI program.

3.1 Inspection Interval

As indicated in Figure 3-1, the first step for defining the inspection interval is to determine the time to reach the CML for AVB wear degradation. As indicated in Section 2.4 either an analytical model for AVB wear, or S/G specific AVB wear service experience, or the lead/trailing plant approach, which uses both analytical wear models and plant service experience, can be used to predict the time wear degradation. Appendix B provides a summary of the analytical model used to predict initiation and growth of AVB wear degradation and the input needed to construct and use the analytical model for AVB wear.

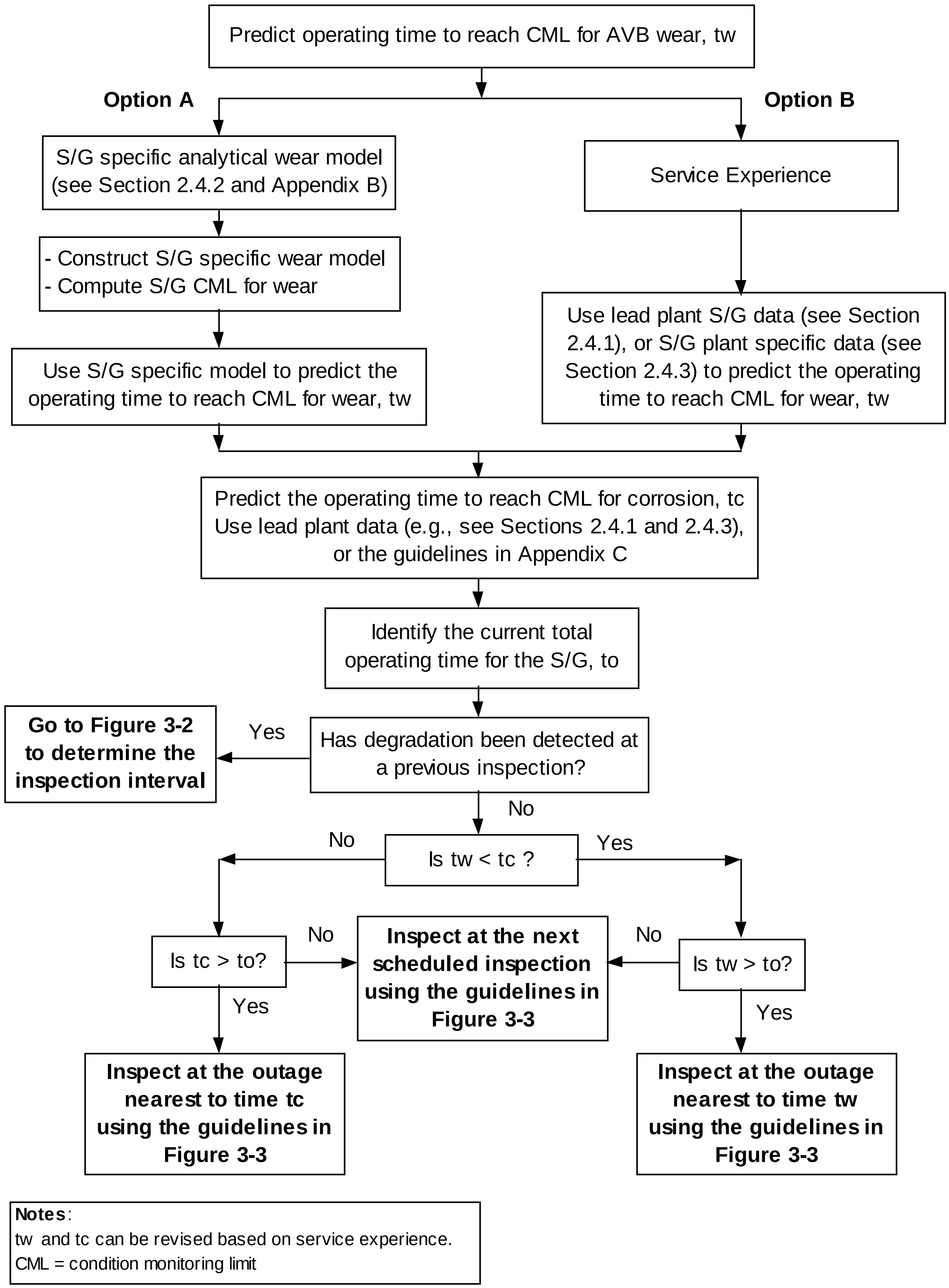


Figure 3-1
Process to Determine Inspection Interval and Sampling

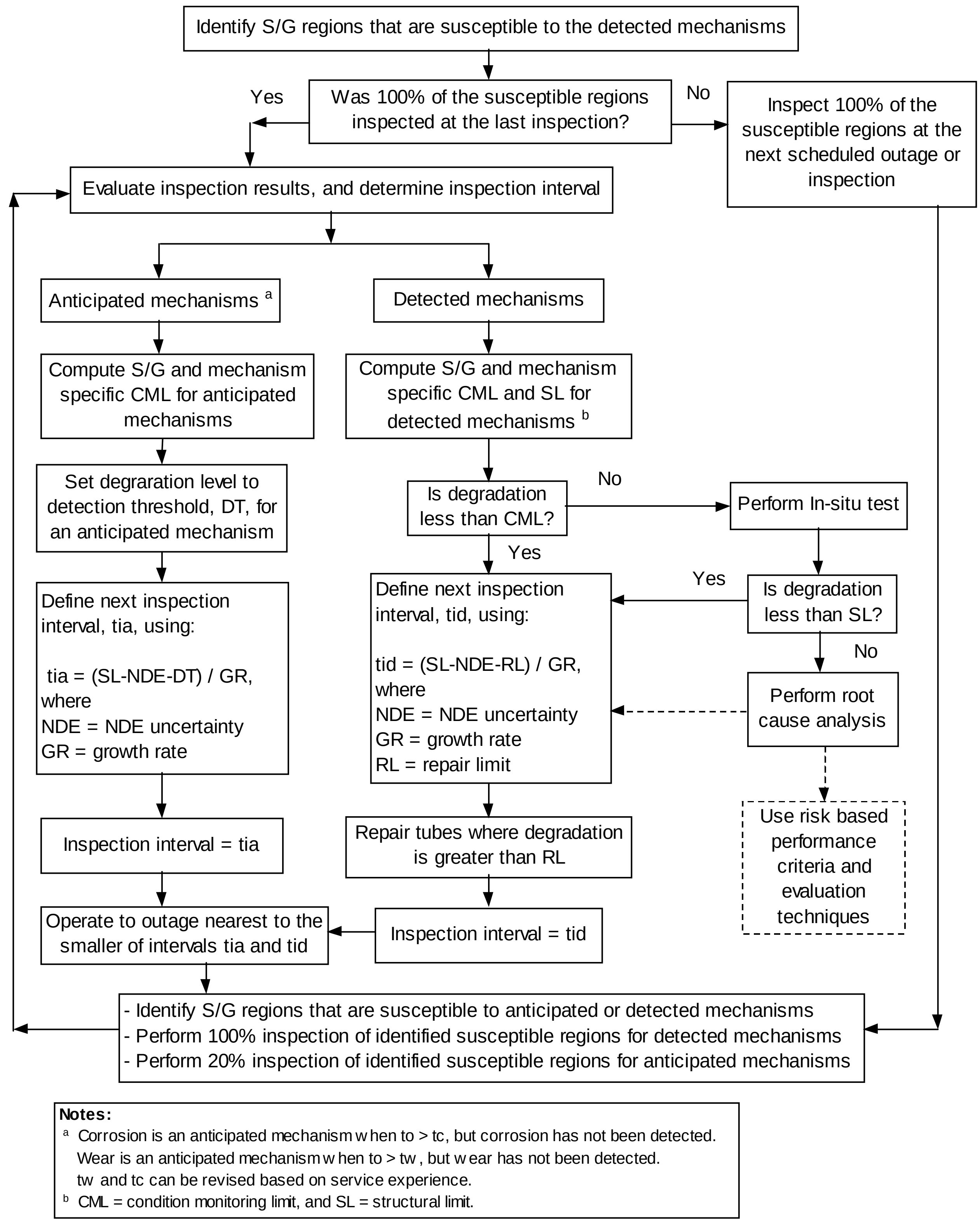
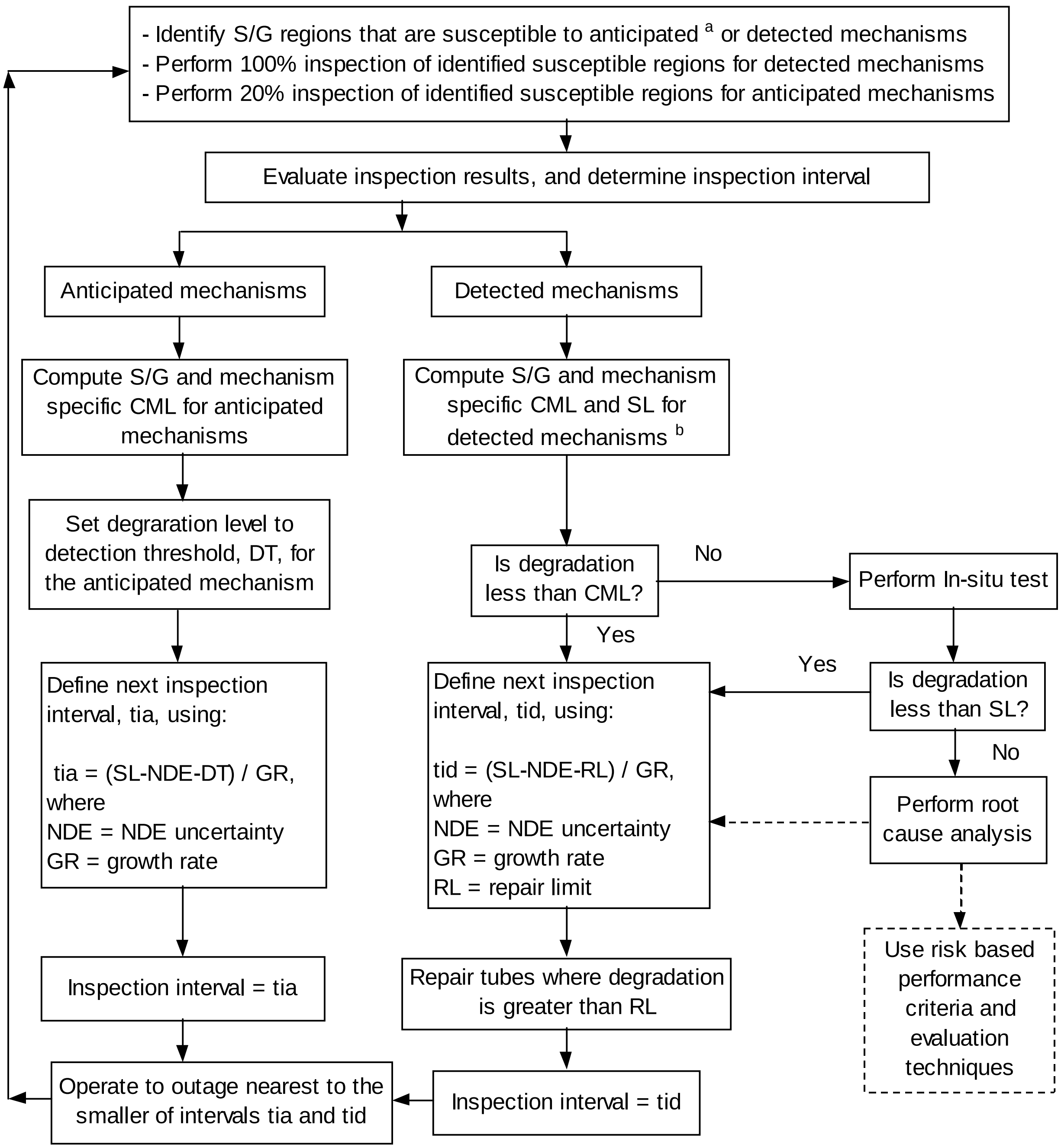


Figure 3-2
Inspection Interval and Sampling for S/Gs Where Degradation is Detected Prior to Implementation of a PBI Program



Notes:

[a] Corrosion is an anticipated mechanism when to > tc, but corrosion has not been detected.
Wear is an anticipated mechanism when to > tw, but wear has not been detected.
tw and tc can be revised based on service experience.

[b] CML = condition monitoring limit, and SL = structural limit.

Figure 3-3
Inspection Interval and Sampling for S/Gs Where Degradation is Detected Subsequent to Implementation of a PBI Program

As indicated in Figure 3-1, the second step for defining the inspection interval is to determine the time to reach the CML for corrosion degradation. Because 2nd generation S/Gs currently have no corrosion degradation, the predicted time to corrosion degradation is based on service experience from 1st generation S/Gs adjusted for improvements made to 2nd generation S/Gs. As described in Section 1.1 these improvements include use of alloy 600TT or 690TT tubes, stainless steel tube supports with quatrefoil, lattice bar or egg crate configurations, and tubes that are hydraulically expanded into the tube sheet.

Predictions of time to corrosion degradation based on service experience from 1st generation S/Gs adjusted for improvements made to 2nd generation S/Gs are presented in Figure C-1 of Appendix C. Figure C-1 is a plot of time (in EFPY) to corrosion degradation as a function of the temperature of the coolant at the inlet to the hot leg piping (T_{hot}) and S/G type. The time shown in Figure C-1 represents an estimate of the time when the value of the NDE measurement parameter first reaches the CML for the indicated mechanisms. The mechanisms identified in Figure C-1 are those where corrosion degradation was estimated to occur at the earliest times. The information in Figure C-1 can be used as guidance in developing predictive models for time to corrosion degradation.

As an alternative, the time to corrosion degradation can be estimated using a lead plant if one is available (for example, see Sections 2.4.1 and 2.4.3). In this instance, the time to corrosion degradation is equal to either of the following. If no corrosion has been detected in the lead plant then the estimated time to corrosion degradation for the trailing plant is the maximum operating time of the lead plant. This estimate can be updated based on subsequent lead plant operating experience. If corrosion has been detected in the lead plant then the estimated time to corrosion degradation for the trailing plant is the time at which tubes in the lead plant would be repaired to meet the structural and leakage performance criteria.

One of two procedures are used to define the inspection interval and inspection scope depending on whether degradation has been detected prior to implementation of the PBI program. If degradation had been detected prior to implementation of a PBI program then Figure 3-2 is used to define the inspection scope and interval. Inspection intervals are determined for both detected and anticipated mechanisms using the evaluation procedures described in Section 2.3. A degradation mechanism is said to be an anticipated mechanism when the operating time exceeds the predicted time for the mechanism to occur, but the mechanism has not yet been detected. For example, if the S/Gs have 14 EFPY of operation and corrosion degradation was predicted to occur in 13 EFPY but was not detected at an inspection at 13 EFPY, then corrosion is an anticipated mechanism for subsequent inspections.

In the event degradation has not been detected prior to implementation of the PBI program then as indicated in Figure 3-1 the inspection interval is the shorter of the predicted time to wear or corrosion degradation. Figure 3-3 then is used to define the inspection scope and interval subsequent to operation following the shorter of the times predicted for wear and corrosion degradation.

3.2 Inspection Sampling

Figures 3-1 through 3-3 define somewhat different requirements for implementing a PBI program depending on whether a degradation mechanism has been detected or is an anticipated mechanism.

Figure 3-2 summarizes the interval determination and sampling when degradation has been detected prior to implementing the PBI program. In this instance, the inspection interval for the detected degradation mechanism is determined using S/G specific service experience, and the inspection scope includes 100% inspection of the S/G and tube regions determined to be susceptible to the detected mechanism. A 100% inspection is used to provide a high degree of assurance that all susceptible tubes are in compliance with the structural and leakage performance criteria. The inspection interval for anticipated mechanisms is determined using the analytical model or lead plant approaches described in Section 2.4, and the inspection scope includes a 20% sampling of the S/G and tube regions determined to be susceptible to the anticipated mechanism. The 20% sampling is used to provide a relatively high degree of assurance that if degradation is present it will be detected.

Figure 3-3 summarizes the interval determination and sampling when degradation has not been detected prior to implementing the PBI program. In this instance, the degradation mechanisms are anticipated mechanisms, the inspection interval is determined using the analytical model or lead plant approaches described in Section 2.4, and the inspection scope includes a 20% sampling of the S/G and tube regions determined to be susceptible to the anticipated mechanism. The 20% sampling is used to provide a relatively high degree of assurance that if degradation is present it will be detected.

The 20% and 100% sample sizes for anticipated and detected degradation mechanisms, respectively, were defined based on the following considerations. A 20% sample is used for detection of an anticipated mechanism because it provides a relatively high level of confidence that the mechanism will be detected if the mechanism is present (90% chance of detecting one degraded tube out of 12 degraded tubes in a S/G). The benefit to cost ratio for detection does not increase substantially for larger sample sizes. However, once degradation is detected then a 100% sample is necessary to provide a high level of confidence that no one tube has a degradation level that exceeds the performance criteria.

If degradation is detected by the 20% sampling while performing the inspections indicated in either Figure 3-2 or 3-3, then additional evaluations and inspections should be performed to assess the extent and severity of the detected degradation. The evaluation and extent of additional inspections should be based on the degradation mechanism, observed degradation growth rate, prior inspection history, and future planned inspection interval. The inspection scope should provide a high degree of assurance that the susceptible region has been bounded and that tubes that may be susceptible to the degradation mechanism do not have degradation levels that exceed the structural and leakage structural criteria.

3.3 In-situ Pressure Testing

Experience shows that there can be a wide range of degradation levels at the end of an operating interval. Occasionally, there can be tubes where the level of degradation exceeds the maximum predicted values and the CML. As indicated in Figures 3-2 and 3-3, an in-situ pressure test would be required to demonstrate compliance with the performance criteria described in Sections 2.1.1 and 2.1.2 for tubes with degradation beyond the CML.

An in-situ pressure test provides an explicit demonstration that the structural and leakage performance criteria are satisfied. The in-situ pressure test is an attractive alternative to pulling tubes where there may be difficulty extracting the tube, and there can be uncertainty associated with interpretation of the test results if the tubes are damaged during the extraction process. In addition, the in-situ pressure test provides assessment of compliance with the performance criteria in real time, rather than waiting for the results from laboratory tests.

In-situ pressure testing procedures have been standardized. The EPRI Steam Generator In-Situ Pressure Test Guidelines [8] provide guidance for performing the tests and interpreting the test results to assess compliance with the performance criteria.

It is recommended that outage planning include the likelihood that in-situ pressure testing would be required to demonstrate compliance with the structural and leakage criteria, especially when inspection intervals are relatively long, and are based on predicted degradation levels up to the CML

On rare occasions the degradation may be so severe that the results from the in-situ pressure test would indicate the performance criteria were not met. In this instance, a root cause analysis would be performed to determine why the actual degradation was substantially greater than the predicted values. The results from the root cause analysis would be used for predicting the subsequent inspection interval to ensure that the actual degradation at the end of the next operating interval does not substantially exceed the predicted value.

In addition to the root cause analysis, a risk analysis may be performed to demonstrate acceptable levels of risk were maintained even though the performance criteria were not met. Major portions of the risk analysis (i.e., the probabilistic risk assessment and T/H analyses) can be performed prior to the inspection, with the final evaluation completed when the degradation distribution is obtained from the inspection results. Performing a risk analysis prior to the inspection will reduce the impact that the time to perform the risk analysis may have on the critical path for plant restart.

3.4 Loose Parts Prevention

Periodic inspection programs may not be effective for monitoring degradation from random events such as loose parts. Consequently, a program to: 1) reduce the likelihood of loose parts in the S/G, 2) detect the presence of loose parts, and 3) remove any detected loose parts that are of a concern, will be required for implementation of a PBI program for 2nd generation S/Gs. Implementation of an effective loose parts prevention and monitoring program will provide defense in depth and greater assurance that the PBI program will be effective, and will reduce the potential for unanticipated tube failure, leakage and plant shutdown.

For new S/Gs a loose parts program would begin at the fabrication shop with implementation of inventory control and visual inspection programs to ensure no foreign objects remain in the S/G when it is shipped to the site. Similarly, inventory control and visual inspection programs would be put into effect at the site to ensure that no foreign objects remain in the S/G following installation. Subsequent to operation, inventory control and visual inspection program should be implemented any time work is performed on the secondary side of the S/G to ensure there are no foreign objects in the S/Gs when they are returned to service.

4
CASE STUDY

This section presents a case study to illustrate application of the procedures described in Sections 2 and 3 for developing and implementing a PBI program. In this example, it is assumed that a PBI program is developed for a plant with 2nd generation Model D5 S/Gs, where wear degradation has been detected previously. In addition, there are sufficient plant specific wear data so the plant specific data approach described in Section 2.4.3 can be used to determine the inspection interval for wear.

4.1 Background

For the plant in this case study, it is assumed that one S/G has been shown, through detailed analysis, to have AVB wear degradation which will most limit future inspection intervals. This S/G will be the focus of this case study. Table 4-1 provides a summary of the cumulative EFPY, number and maximum depth (in %TW) of the indications detected, number of repaired tubes and the maximum and average growth rates (%TW/EFPY) at each inspection up through refueling outage seven (RFO 7). The information in Table 4-1 indicates that the size of the largest indications and growth rate (GR) for the degradation has diminished over time. The distributions of indications and growth rates at RFO 7 are presented in Figures 4-1 and 4-2, respectively, for the S/G with the most indications and highest growth rates.

Table 4-1
History of AVB Wear Degradation in Limiting Steam Generator

Refueling Outage	Cumulative EFPY	Number of Indications	Largest Indication (%TW)	Number of Repaired Tubes	Maximum Growth Rate (%TW/EFPY)	Average Growth Rate (%TW/EFPY)
1	1.61	36	53	5	45.7	21.1
2	2.29	73	53	8	20.4	12
3	3.41	127	54	12	17.9	6.1
4	4.57	173	47	4	17.2	2.7
5	5.84	202	43	4	10.2	2.6
6	7.16	211	45	4	7.9	1.5
7	8.57	197	39	0	6.2	1.0

Note: Tubes repaired based on a 40% TW repair limit.

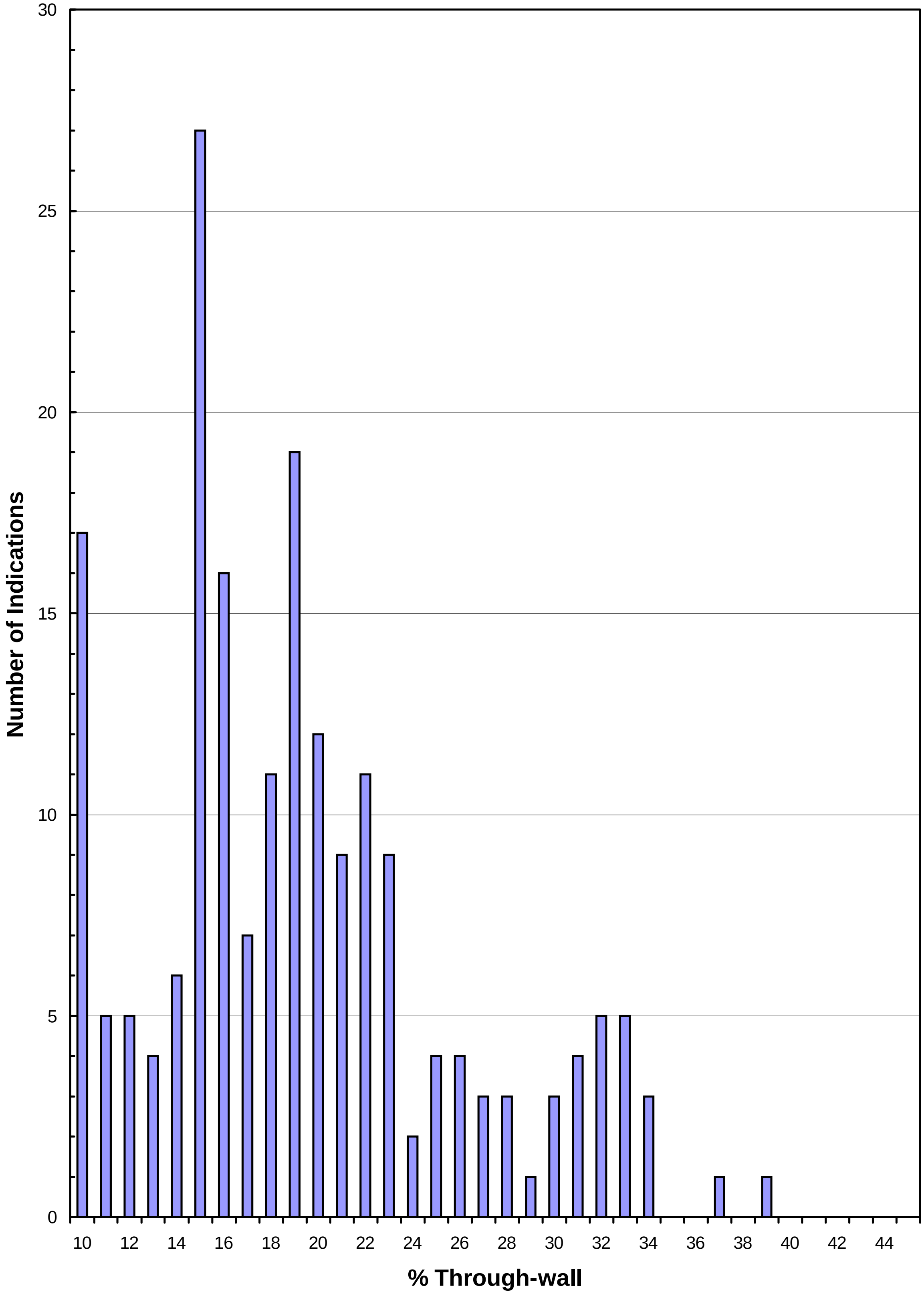


Figure 4-1
Distribution of AVB Wear Indications at Refueling Outage 7

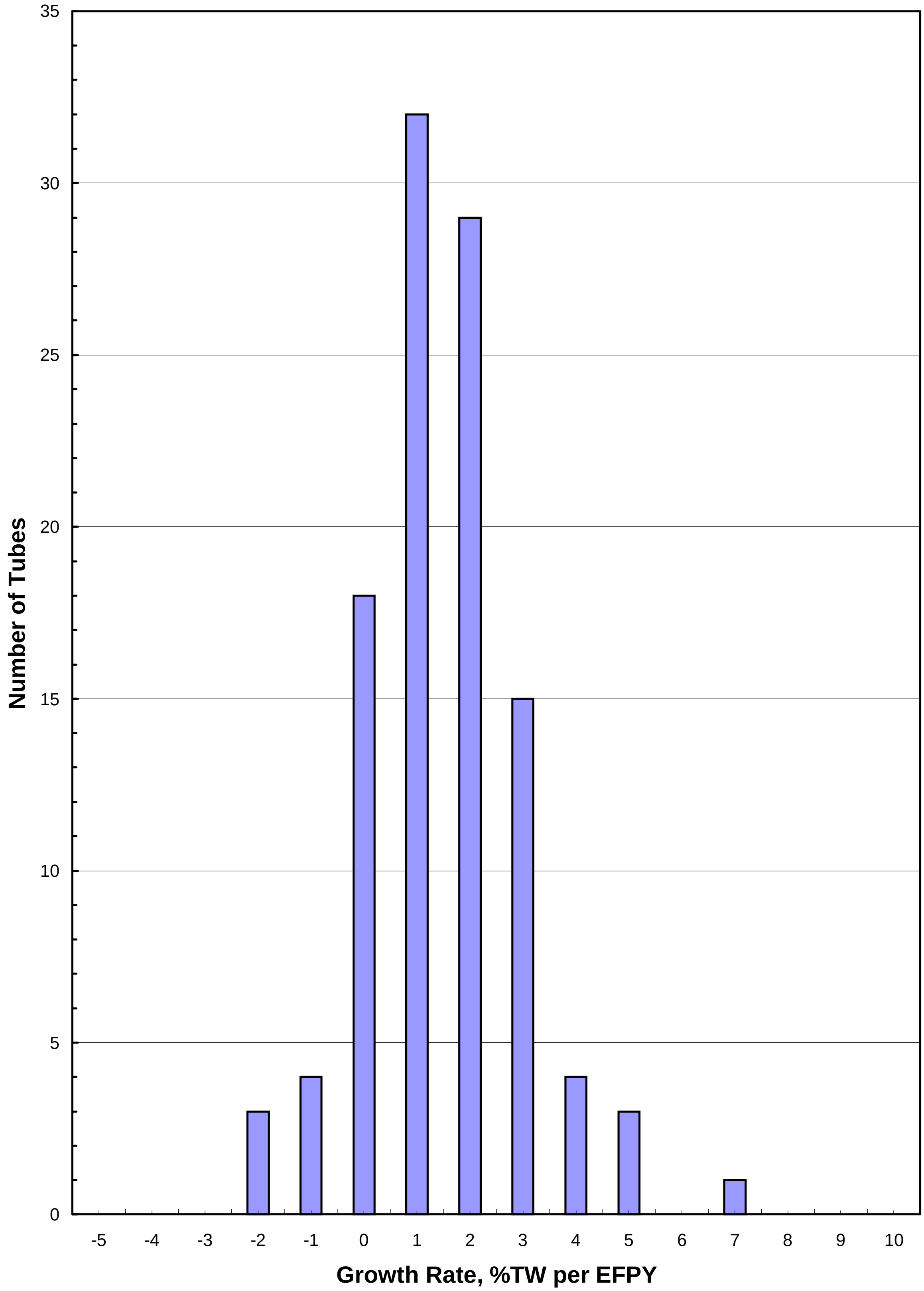


Figure 4-2
Degradation Growth Rate Distribution for AVB Wear Indications at Refueling Outage 7

Following the evaluation procedure outlined in Figure 3-1 the time to corrosion degradation is determined using Figure C-1 from Appendix C. In this example, T_{hot} is equal to 610°F (321.1°C), and the predicted time to corrosion degradation is approximately 17 EFPY.

The most likely forms of corrosion degradation at about 17 EFPY are hot leg intergranular attack (IGA)/stress corrosion cracking (SCC) at the tube support plates (TSP) and hot leg expansion zone (EZ) primary water stress corrosion cracking (PWSCC).

4.2 Performance Based Inspection Interval Evaluation

Because wear degradation was detected prior to implementation of the PBI program, Figure 3-2 is used to determine the inspection scope and interval, and wear is evaluated as a detected mechanism in Figure 3-2. However, corrosion degradation will not be an anticipated mechanism until the S/Gs accumulate an additional 8 EFPY.

According to Figure 3-2, if the inspection at RFO 7 included 100% of the region susceptible to wear then the PBI program can be implemented immediately. Assuming that a 100% inspection of the region susceptible to wear was inspected at RFO 7 then the parameters listed in Figure 3-2 are computed for the detected wear mechanism to complete the inspection interval assessment.

For illustration purposes the deterministic, performance based inspection interval will be determined using the arithmetic, simplified statistical, and Monte Carlo approaches described in [4]. Table 4-2 contains the information needed to determine the inspection interval using the evaluation procedures and guidelines described in Sections 2 and 3.

Table 4-2
Data For Determination of the Performance Based Inspection Interval

Variable	Variable Value
Tube alloy and thermal treatment	600 TT
Tube outer diameter, OD	0.75 inch (19.05 mm)
Tube wall thickness, t	0.043 inch (1.0922 mm)
Mean yield plus ultimate stress, $S_y + S_u$	137,370 psi (947 MPa)
Standard deviation yield + ultimate stress, σ	7,242 psi (49.9 MPa)
3 x normal operating pressure, P	4,050 psi (27.9 MPa)
NDE analyst uncertainty, AU	7.04 %TW
NDE technique uncertainty, TU	3.82 %TW
Coolant temperature at hot leg piping, T_{hot}	610 °F (321.1°C)

4.2.1 Arithmetic Approach

First, the CML and SL for wear degradation are obtained from the relationship between burst pressure and the flaw dimensions, where the burst pressure is adjusted for uncertainty in the material properties and the burst pressure versus flaw size correlation [4]. This relationship was obtained from Section 5.5.2 of [9] and is:

$$P = 0.58\left(S_y + S_u - 1.28\sigma\right)\left(t / R_i\right)\left[1 - \left(d / t\right)\left(L / \left(L + 2t\right)\right)\right] + 180, \qquad \textbf{Eq. 4-1}$$

where P = 3 times the normal operating pressure differential = 4,050 psi (27.9 MPa), d is the flaw depth, L is the flaw length (assumed to be equal to one inch for this example), R_i is the tube inner radius, and the ratio d/t is the SL. Substituting the values from Table 4-2 into this equation and solving for d/t results in a calculated SL = 65.6%TW.

Because the SL is significantly less than 100%TW then the leakage performance criteria are automatically satisfied by compliance with the structural criterion, and an additional leakage evaluation is not required.

The CML is determined by adjusting the SL for the NDE system uncertainty (SU). The NDE system uncertainty is computed from the relationship [4]

$$SU = 1.28\left(AU + TU\right) = 1.28\left(7.04 + 3.82\right) = 13.9\%TW,$$

where the values for AU and TU were obtained from Table 4-2. The CML then is determined from the relationship

$$CML = SL - SU = 65.6 - 13.9 = 51.7\%TW.$$

In accordance with the procedure outlined in Figure 3-2 the detected indications are compared to the CML. From Table 4-1, the largest indication is 39%TW, which is less than the calculated CML. Consequently, the structural performance criterion is satisfied, and the inspection interval can be computed.

From Figure 3-2 the inspection interval for detected mechanisms, t_{id}, is determined from the relationship

$$\begin{aligned} t_{id} &= \left(SL - SU - RL\right)/ GR \\ &= \left(65.6\%TW - 13.9\%TW - 39\%TW\right)/ 6.2\%TWperEFPY = 2.05EFPY. \end{aligned}$$

Because no tubes were repaired at RFO 7 the repair limit, RL, was taken as the largest indication left in service, i.e., 39%TW (see Table 4-1). The growth used in the calculation was the maximum computed from the inspection results at ROF 7 (see Table 4-1).

The maximum inspection interval is somewhat more than one operating cycle (assuming 1.4 EFPY per operating cycle). This relatively short interval results from using the maximum growth rate, which is relatively conservative. As indicated in [4] the conservatism can be reduced by using the 95 percentile growth rate instead of the maximum growth rate if there are at least 50 data points available to compute the 95 percentile value. As can be seen from Figure 4-2 there are more than 50 data points, and the 95 percentile growth rate estimated from the data in Figure 4-2 is approximately 4 %TW per EFPY. The corresponding inspection interval then is computed from

$$\begin{aligned} t_{id} &= (SL - SU - RL)/GR \\ &= (65.6\%TW - 13.9\%TW - 39\%TW)/4\%TWperEFPY = 3.2EFPY. \end{aligned}$$

This inspection interval computed for AVB wear is about two operating cycles. Comparison of the inspection interval computed for AVB wear with the time to corrosion degradation indicates that the inspection interval is governed by wear degradation.

Consequently, the inspection interval that satisfies the performance criteria extends from RFO 7 to RFO 9. At RFO 9 the cumulative operating time is 11.4 EFPY. As indicated earlier, the predicted time to corrosion degradation is approximately 17 EFPY. This means that following 100% inspection of the region susceptible to AVB wear at RFO 7 the S/Gs could run two cycles before the next inspection at RFO 9.

As indicated in Figure 3-2, 100% of the region susceptible to wear would be inspected at RFO 9. The inspection results would be compared to the CML, which is approximately 51%TW to assess compliance with the performance criteria. Following the conditioning monitoring assessment a new inspection interval is determined using the procedure in Figure 3-2. Because the time at RFO 9 is less than the time predicted for corrosion degradation, no inspection of non-AVB regions to detect corrosion degradation is required at RFO 9.

The equation in Figure 3-2 for calculating the inspection interval for detected mechanisms, shows that the inspection interval can be lengthened by decreasing the repair limit, RL. For example, assume that at RFO 7 a 30%TW repair limit was used prior to restart, and the applicable growth rate is the 95 percentile value of 4 %TW per EFPY. In this instance, the inspection interval, t_{id}, from the previous equation is 5.4 EFPY or more than three operating cycles. This example shows how changing RL from about 40 %TW to 30 %TW can extend the inspection interval an additional cycle.

4.2.2 Simplified Statistical Approach

The simplified statistical approach is similar to the arithmetic approach except that the material and burst pressure uncertainties are converted to uncertainties in the NDE measurement parameter, and then combined with the NDE uncertainties using the square root of the sum of the squares [4].

As indicated in [4] the material and relational uncertainties for the burst curve are determined by taking differences between the structural limits computed for mean and mean minus 1.28 standard deviation values. Variations of Equation 4-1 are used to determine the material and relational uncertainties. Equation 4-1 represents the structural limit adjusted for material and relational uncertainty. The material uncertainty is represented by the 1.28σ term in Equation 4-1.

The relational uncertainty in the burst relationship is represented in [9] by a constant. To represent the lower bound curve (Equation 4-1), this constant is 180. Removing the 1.28σ term and replacing the value of 180 by 291 [9] will provide a mean structural limit. In fact, the 180 term provides a more conservative limit compared to a mean minus 1.28 sigma value. However, the relational uncertainty is relatively small and the constant value of 180 is used to represent the mean minus 1.28 sigma relational uncertainty .

To compute the relational uncertainty, the standard deviation term for the material is removed from Equation 4-1. Then the mean structural limit is computed using the constant 291, and the mean minus 1.28 sigma value of the structural limit is computed using the constant 180. The resulting mean and mean minus 1.28 standard deviation values computed in this manner are 69% TW and 67.9% TW, respectively. The relational uncertainty then is 69 – 67.9 = 1.1%TW.

To compute the material uncertainty, the relational constant is set to 291 in Equation 4-1. Then the mean structural limit is computed using the mean value of $S_y + S_u$, and then the mean minus 1.28 sigma value of $S_y + S_u$. The resulting mean and mean minus 1.28 standard deviation values computed in this manner are 69% TW and 67.9% TW, respectively. The material uncertainty then is 69 – 66.2 = 2.8%TW.

The combined uncertainty, CU, then is computed as [4]:

$$CU = \sqrt{(1.28x7.04)^2 + (1.28x3.82)^2 + 1.1^2 + 2.8^2} = 10.7\% TW$$

The mean structural limit is computed using Equation 4-1 where the standard deviation term for the material is removed and the relational constant is changed from 180 to 291, and is equal to 69% TW.

The CML for the simplified statistical approach then is determined from the relationship

$$CML = meanSL - CU = 69 - 10.7 = 58.3\% TW.$$

The inspection interval is computed assuming the plant has already returned to service at the end of RFO 7, so the repair limit is 39% TW, and using the 95 percentile growth rate, the inspection interval is

$$\begin{aligned} t_{id} &= (meanSL - CU - RL)/GR \\ &= (69\% TW - 10.7\% TW - 39\% TW)/4\% TWperEFPY = 4.8 EFPY. \end{aligned}$$

This corresponds to more than three operating cycles (assuming 1.4 EFPY per cycle), and the inspection interval that satisfies the performance criteria extends from RFO 7 to RFO 10. At RFO 10 the cumulative operating time is 12.8 EFPY. As indicated earlier, the predicted time to corrosion degradation is approximately 17 EFPY. This means that following 100% inspection of the region susceptible to wear at RFO 7, the S/Gs could run three cycles before the next inspection at RFO 10.

As indicated in Figure 3-2, 100% of the region susceptible to wear would be inspected at RFO 10. The inspection results would be compared to the CML, which is approximately 58%TW to assess compliance with the performance criteria. Following the conditioning monitoring assessment a new inspection interval is determined using the procedure in Figure 3-2. Because the time at RFO 10 is less than the time predicted for corrosion degradation, no sampling to detect corrosion degradation is required at RFO 10.

Monte Carlo sampling techniques can be used to further reduce the conservatism in the inspection interval computations for AVB wear. The following section illustrates application of the STEIN [5] software to compute the inspection interval for AVB wear.

4.2.3 Monte Carlo Approach

The inspection interval is determined using the operational assessment option of the STEIN software. The input needed to run the operational assessment option for the STEIN software is included in Table 4-3.

Table 4-3
Input to Determine the Operating Interval Using the STEIN Software

Variable	Variable Value
Burst pressure vs NDE measurement parameter data	Table 4-4
Mean $S_y + S_u$	137,370 psi (947 MPa)
Standard deviation for $S_y + S_u$	7,242 psi (49.9 MPa)
Reference stress	137,370 psi (947 MPa)
Leak rate vs NDE measurement parameter data	Table 4-5
Distribution of indications	Figure 4-1
Distribution of repaired indications	None Repaired
Probability of detection, POD	Constant = 0.9
Growth rate distribution	Figure 4-2
Accident pressure	2,560 psi (17.65 Mpa)
Cycle length	Variable
Analyst uncertainty & cut off	.0704 & 0.8
Probe wear (technique uncertainty) & cut off	.0382 & 0.8
Other uncertainty & cut off	0 & 0

Application of the STEIN software requires the NDE measurement uncertainties for both analyst and technique to be in a form where the standard deviation is normalized with respect to the mean. For this case study, the NDE uncertainties used in the STEIN software were taken to have the same numerical values as the NDE uncertainties used in Sections 4.2.1 and 4.2.2. This was done for illustration purposes, only. Subsequent work will develop the procedures necessary for implementing consistent and compatible NDE uncertainty data for STEIN calculations as stipulated in [4].

Data that represents the mean relationship between tube burst pressure and the NDE measurement parameter is a required input to STEIN. Because no actual experimental data were available, representative burst data were generated from a Monte Carlo simulation. The simulation used the mean burst pressure versus flaw size relationship from Section 5.5.2 of [9]:

$$P = 0.58(S_y + S_u)(t / R_i)[1 - (d / t)(L / (L + 2t))] + 291$$

with $S_y + S_u = 137{,}370$ psi (947 MPa), a flaw length, L, of one inch (25.4 mm), and a standard deviation of 70 psi (.483 MPa) for the burst pressure relationship. Table 4-4 lists the burst pressure versus flaw depth data obtained from the simulation and input into STEIN.

Generally, the burst pressures are normalized by a reference value of $S_y + S_u$, and this reference value is an input to STEIN. The normalization is used so that the burst pressure correlation can be applied for any heat of material. For this example, the reference value of $S_y + S_u$ was set equal to the mean value of $S_y + S_u$, as indicated in Table 4-3

Although leakage in not relevant for this example because the SL is far from through-wall, leak rate data is a required input into STEIN. Consequently, hypothetical leak rate data, presented in Table 4-5, were input into STEIN.

The STEIN computational option computes a distribution of degraded tubes as a function of the NDE measurement parameter. Because the degradation predicted by STEIN is represented by a distribution, there are fractions of a tube in the distribution tail. As indicated in Section 2.3, the tail of the distribution at the end of the operating interval is integrated back from the maximum value of the NDE measurement parameter in the distribution until the sum of the fractional tubes is equal to one.

Table 4-4
Simulated Burst Data

d/t, %	P, ksi	d/t, %	P, ksi	d/t, %	P, ksi
30	7.79	60	4.87	80	2.94
30	7.68	60	4.98	80	3.11
30	7.82	60	4.79	80	3.18
30	7.75	60	5.03	80	2.98
30	7.82	60	4.90	80	3.01
30	7.69	60	5.00	80	2.85
30	7.74	60	4.92	80	3.01
30	7.70	60	4.96	80	3.08
30	7.74	60	4.97	80	3.03
30	7.73	60	5.00	80	3.09
30	7.68	60	4.85	80	3.10
30	7.63	60	5.04	80	3.05
30	7.70	60	5.06	80	3.02
30	7.78	60	4.91	80	3.03
30	7.81	60	4.96	80	2.91
30	7.77	60	4.93	80	3.04
30	7.68	60	4.95	80	3.04
30	7.69	60	4.87	80	3.05
30	7.80	60	4.93	80	3.13
30	7.68	60	4.87	80	3.08
40	6.85	70	3.93	90	2.08
40	6.95	70	4.03	90	2.06
40	6.83	70	3.95	90	1.94
40	6.76	70	3.88	90	2.02
40	6.84	70	3.90	90	2.07
40	6.63	70	3.98	90	2.05
40	6.63	70	3.93	90	2.01
40	6.71	70	3.86	90	2.14
40	6.80	70	3.98	90	1.99
40	6.84	70	4.00	90	2.09
40	6.73	70	3.91	90	1.92
40	6.81	70	3.82	90	2.07
40	6.96	70	3.98	90	2.05
40	6.78	70	4.06	90	2.05
40	6.75	70	4.01	90	1.97
40	6.76	70	3.92	90	2.15
40	6.74	70	4.10	90	2.01
40	6.74	70	4.05	90	2.10
40	6.70	70	3.96	90	2.11
40	6.92	70	3.94	90	2.03

Table 4-5
Hypothetical Leak Rate Data

d/t, %	LR, gpm	d/t, %	LR, gpm	d/t, %	LR, gpm
2	0	95	4.8E-02	15	0
6	0	23	0	13	0
4	0	3	0	15	0
5	0	86	1.3E-02	4	0
10	0	99	4.4E-02	8	0
7	0	70	2.3E-02	5	0
7	0	9	0	16	0
6	0	84	1.3E-02	8	0
3	0	43	0	20	0
10	0	98	3.9E-02	13	0
3	0	84	3.2E-02	15	0
4	0	92	2.1E-01	35	8.6E-03
3	0	20	0	11	8.8E-05
6	0	19	0	96	1.1E+01
8	0	26	0	98	6.0E-01
3	0	36	0	99	9.7E+00
3	0	41	0	34	0
5	0	6	0	50	3.7E-03
2	0	95	1.2E-01	37	0
12	0	28	0	21	1.8E-04
6	0	13	0	2	0
2	0	71	7.4E-02	9	0
25	0	90	2.4E-01	91	5.6E-02
6	0	59	1.2E-02	59	1.8E-02
94	5.8E-01	60	8.0E-03	3	0
44	0	88	8.8E-05	3	0
100	8.8E-03	98	3.2E-02	90	9.7E-02
98	4.2E-01	85	1.0E-01	2	0
18	0	94	2.3E-01	26	0
85	2.4E-01	43	1.5E-01	11	0
90	6.1E-01	42	1.1E-03	5	0
86	9.5E-02	97	3.9E-01	1	0
49	0	57	0	4	0
98	2.1E-01	96	4.1E-02	1	0
8	0	19	0	14	0
60	8.8E-03	96	2.2E-01	4	0
10	0	92	1.0E-01	49	1.6E-02
97	4.0E-01	20	0	57	1.8E-04
6	0	22	0	66	4.4E-03
97	1.4E+00				

The value of the NDE measurement parameter where the sum of the fraction of tubes is equal to one is the value compared to the SL (adjusted for material and relational uncertainty, see Section 4.2.1) to assess compliance with the performance criteria. A trial and error procedure was used to determine the time where the value of the NDE measurement parameter equals the SL. The computational results at each assumed operating time from the end of RFO 7 are presented in Table 4-6.

Table 4-6
Results from STEIN Calculation

RFO	EFPY After RFO 7	Cumulative EFPY	%TW Integrated Back to One Tube
7	N/A	8.6	N/A
8	1.405	10.0	43
9	2.810	11.4	46
10	4.215	12.8	51
11	5.620	14.2	57
12	7.025	15.6	63
13	8.430	17.0	70

Note: EFPY projections are based on 1.405 EFPY per operating cycle.

The results presented in Table 4-6 indicate that at RFO 12 the projected degradation is slightly less than the SL of 65.6%TW computed in Section 4.2.1, and the end of the inspection interval based on AVB wear is 15.6 EFPY. As indicated earlier, the predicted time to corrosion degradation is approximately 17 EFPY. Consequently, the inspection interval is limited by AVB wear and extends from RFO 7 to RFO 12. This means that following 100% inspection of the region susceptible to AVB wear at RFO 7, the S/Gs could run five cycles before the next inspection at RFO 12.

As indicated in Figure 3-2, 100% of the region susceptible to AVB wear would need to be inspected at RFO 12. The inspection results would be compared to the CML, which is approximately 58%TW (see Section 4.2.2), to assess compliance with the performance criteria. As an alternative, Monte Carlo sampling could be used to define the CML. The sampled value of CML likely would be higher than the deterministic value. A new inspection interval for AVB wear would then be determined based on the inspection results and the repair limit used for degraded tubes.

At RFO 13 the cumulative EFPY would be 17 EFPY, and corrosion would be an anticipated mechanism. Consequently, a 20% sampling of the region evaluated to be susceptible to corrosion would be required at RFO 13 as indicated in Figure 3-2. As indicated earlier the anticipated mechanisms and the associated susceptible regions are hot leg IGA/SCC at the TSPs and hot leg EZ PWSCC.

As an alternative to inspecting at RFO 12 due to AVB wear and at RFO 13 due to anticipated corrosion mechanisms, inspections could be performed at RFO 10 and 13. This action would still result in one inspection prior to RFO 13, but has the advantage that there would be more margin for compliance with the performance criteria in regions susceptible to wear.

4.3 In-situ Pressure Testing

For any PBI program that results in inspection intervals longer than prescriptive industry requirements, it would be prudent to be prepared to perform in-situ pressure tests during inspection outages in the event the level of degradation exceeds the CML. The in-situ pressure test would provide a definitive indication of compliance with the performance criteria in the event the CML is exceeded. The in-situ pressure test should be performed using industry guidelines [8].

4.4 Loose Parts Prevention

Loose parts inventory control and visual inspection programs should be implemented on the secondary side of the S/G prior to plant restart to ensure the absence of foreign objects as outlined in Section 3.4.

5 CONCLUSIONS AND RECOMMENDATIONS

A methodology has been developed to determine inspection intervals based on meeting structural and leakage performance criteria, rather than using prescriptive intervals as specified in the current T/S and ISI Guidelines [2]. Implementing an inspection program based on meeting structural and leakage performance criteria would ensure that adequate safety margins are maintained and, at the same time, reduce the number of inspections, inspection costs and personnel radiation exposure.

Implementation of PBI programs will have the greatest benefit for 2nd generation S/Gs. PBI programs will be effective when they are implemented for times: prior to initiation of significant wear degradation, during periods of low wear rates and prior to initiation of significant corrosion degradation. Should degradation become extensive, then risk-based performance criteria can be implemented to define the maximum inspection interval and ensure adequate structural and leakage integrity is maintained during operation.

Three approaches have been defined to obtain the information needed to develop PBI programs. The availability of the three approaches provides the opportunity for most plants with 2nd generation S/Gs to implement inspection programs with performance based inspection intervals.

A compliment to implementation of a PBI program is the use of in-situ pressure testing and loose parts prevention programs. In-situ pressure testing can be employed to demonstrate that the structural and leakage performance criteria are met when the inspection results indicate the degradation is outside the limits allowed by the performance criteria. Loose parts prevention, detection and retrieval programs are used to preclude the presence of foreign objects in the S/Gs and reduce the likelihood of unanticipated tube degradation and failure.

A case study, using plant specific inspection results, showed that an inspection interval of five operating cycles could be justified and would result in considerable savings in inspection costs.

Additional case studies should be performed to illustrate the implementation of both deterministic and risk based performance criteria. Also, pilot plant programs should be initiated to allow plants to take advantage of the inspection cost savings that could result by using the various approaches to implement PBI programs.

6 GLOSSARY

1st Generation Steam Generators—Steam generators that have any one of the following conditions: mill annealed alloy 600 tubes, carbon steel support plates with drilled holes, or tubes that were either explosively expanded or hard rolled into the tube sheet. Up until several years ago, 1st generation S/Gs were original equipment in pressurized water reactors.

2nd Generation Steam Generators—Steam generators that have thermally treated alloy 600 or 690 tubes, stainless steel tube supports with quatrefoil, lattice bar or egg crate configurations, and tubes that are hydraulically expanded into the tube sheet. The 2nd generation S/Gs are being used as original equipment for newer plants, and as replacements for plants with 1st generation S/Gs.

Anticipated Degradation Mechanism—A degradation mechanism is an anticipated mechanism when the operating time exceeds the predicted time for the mechanism to occur, but the mechanism has not been detected.

Condition Monitoring—Condition monitoring is the process used to assess the condition of steam generator tubes subsequent to an operating period to determine if adequate margins against leakage and failure were maintained during the operating period. The results from condition monitoring evaluations are used to determine if remedial measures, such as increased monitoring or changes in analysis assumption are required to ensure structural and leakage integrity for future operation.

CDF—The frequency with which core damage (the reactor core is not adequately cooled in a manner consistent with the design basis) is predicted to occur from a sequence of events that may include equipment failure or malfunction, operator error, or external events, such earthquake. Core damage frequencies are estimated as ranging from 10^{-3} to 10^{-5} per operating reactor year. Severe CDF is associated with complete core melt and may be two to three orders of magnitude lower. CDF is one of the quantitative measures used in risk analyses.

Deterministic—A variable or process is deterministic if it has little or no random variation.

Inspection Interval (maximum)—The operating time from the last inspection to the time just prior to when the maximum degradation in any tube does not exceed the degradation allowed by the deterministic structural and leakage performance criteria.

Lead and Trailing Plants (S/Gs)—Lead and trailing plants are plants that have S/Gs with "similar" T/H and structural characteristics so that the degradation histories of the S/Gs over time is expected to be essentially the same for both plants. The plant (i.e., S/G) with the shorter operating time and little or no S/G tube degradation is the trailing plant, and plant(s) with “similar” S/Gs and longer operating times is the lead plant. A trailing plant will use the experience from a lead plant(s) to define their inspection interval. A lead plant may or may not have a history of tube degradation.

LERF—Large early release frequency is the frequency that there will be a large release of radioactive material to the area outside containment. LERF is one of the quantitative measures used in risk analyses, especially for severe accidents (postulated events that are more severe than the design basis) where core melt and release outside containment are postulated events. LERF may be an order of magnitude lower than the core melt frequency.

Operational Assessment—Operational assessment is the process used prior to a period of operation to predict the condition of steam generator tubes at the end of an operating period and determine if adequate margins against leakage and failure are likely to exist at the end of the operating period.

Performance Based—Performance based is a process used to determine if components and systems are operating successfully based on monitoring the condition of the systems or components either continuously or periodically during operation. Performance based programs are implemented to assess the effectiveness of ISI or integrity assessment programs.

Performance Based Inspection (PBI) Program—A PBI program is an inspection program where the maximum inspection interval has been determined using evaluation procedures and acceptance criteria that ensure compliance with specified performance criteria.

Probabilistic—A variable or process is probabilistic if it has a random variation and may be described by a distribution of possible values or outcomes.

Probability of Detection—The probability of detecting a flaw during a steam generator inspection.

Repair Limit—Those NDE measured parameters at or beyond which the tube must be repaired or removed from service by plugging. The repair limit will be determined by either subtracting margins for NDE uncertainty and degradation growth from the structural limit or by conducting a probabilistic analysis.

Risk—Risk is the product of an event frequency and the consequence of the event should it occur. Quantitative measures of risk include CDF and LERF. For example, assume the event is a pipe failure that occurs with a certain frequency, i.e., pipe failures/operating year, and the consequence is the conditional probability of core damage assuming the pipe break occurs, i.e., core damage/pipe failure. Then, Risk = pipe failures/operating year * core damage/pipe failure = core damage/operating year = CDF.

Risk Based—Evaluation procedure and acceptance criteria that use quantitative risk measures, such as CDF or LERF, to determine if an adequate margin against failure or leakage in nuclear components or systems exits for a specified set of inspection, material, degradation, or operational conditions.

Risk Informed Inspection (RII) Program—A RII program is an inspection program where the inspection interval has been determined using deterministic evaluation procedures and acceptance criteria that ensure compliance with deterministic performance criteria, and a risk evaluation has shown that using the deterministic acceptance criteria will not increase the LERF.

STEIN—STEIN is software developed by EPRI to evaluate the structural and leakage integrity of degraded steam generator tubes. The software performs operational assessment and condition monitoring evaluations for a distribution of degraded steam generator tubes and provides results to determine if the degraded tube meet regulatory performance criteria for operational assessment and condition monitoring.

Structural Limit—The value of the NDE measurement parameter that correspond to the margins against tube rupture specified by the structural performance criteria is defined as the structural limit (SL). The SL is determined from experimental or analytical relationships between burst pressure and the NDE measurement parameter for degraded tubes. The structural limit includes adjustments for uncertainty in the relationship and material properties. If these adjustments for uncertainty are not included the value of the structural limit is designated as the mean structural limit in this report.

7
LIST OF ACRONYMS

AU	NDE analyst uncertainty
AVB	Anti vibration bar
BOI	Beginning of an operating interval
CDF	Core damage frequency
CML	Conditioning monitoring limit
CU	Combined uncertainty
EFPY	Effective full power years
EOI	End of an operating interval
EZ	Expansion zone
gpd	Gallons per day
gpm	Gallons per minute
GR	Degradation growth rate
IGA	Intergranular attack
ISI	Inservice inspection
LERF	Large early release frequency
MA	Milled annealed
NDE	Non destructive examination
OD	Tube outer diameter
ODSCC	Outside diameter stress corrosion cracking
PBI	Performance based inspection
POD	Probability of detection
PWR	Pressurized water reactor
PWSCC	Primary water stress corrosion cracking
RFO	Refueling outage
RL	Repair limit
SCC	Stress corrosion cracking
S/G	Steam generator
SGTR	Steam generator tube rupture
SL	Structural limit
SU	NDE system uncertainty
T/H	Thermal hydraulic
TRM	Technical Requirements Manual
T/S	Technical specifications
TSP	Tube support plate
TT	Thermally treated
TU	NDE technique uncertainty
TW	Through-wall
US	United States

8
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A SERVICE EXPERIENCE

This section presents a brief summary of tube degradation in 1^{st} and 2^{nd} generation S/Gs in the United States. The purpose of this summary is to illustrate the differences in tube degradation in 1^{st} and 2^{nd} S/Gs. For illustration purposes the 2^{nd} generation S/Gs are divided into two categories; namely; Models BWI and D75, and Model D5 and F Type. These two groups were used because Models BWI and D 75 have alloy 690TT tubes, while Models D5 and F Type generally have alloy 600TT, although the most recent F Type S/Gs do have alloy 690TT tubes. The 1^{st} generation S/Gs include S/Gs from the three PWR vendors in the United States. All data were obtained from the EPRI Steam Generator Degradation Database [6].

Figure A-1 presents the cumulative number of repaired tubes to the last inspection as a function of EFPY at the last inspection for all degradation mechanisms in [6], except “other”. The data in Figure A-1 indicate a much higher incidence of repaired tubes for 1^{st} generation S/Gs compared to 2^{nd} generation S/Gs.

Figure A-2 presents the number of repaired tubes at each outage as a function of EFPY at each outage for the corrosion degradation mechanisms thinning, pitting, SCC and IGA. The data in this figure indicate a very large incidence of corrosion degradation for 1^{st} generation S/Gs, but virtually no corrosion degradation for 2^{nd} generation S/Gs.

The corrosion degradation that is shown in Figure A-2 for 2^{nd} generation S/Gs is from one plant. While the S/Gs in this plant have most of the attributes of a 2^{nd} generation S/Gs, they have alloy 600MA tubes for a portion of the total tubes in the S/Gs, and these tubes have the corrosion degradation. Because these S/Gs have alloy 600MA tubes they are not classified as 2^{nd} generation S/Gs for purposes of this work, but are shown as 2^{nd} generation S/Gs in Figure A-2 to illustrate their susceptibility to corrosion degradation even when they have other improvements to mitigate corrosion degradation.

Figure A-3 presents the number of repaired tubes at each outage as a function of EFPY at each outage for the mechanical degradation mechanisms fatigue, impingement, and wear. The data shown in this plot indicate a much more even distribution of degradation between 1^{st} and 2^{nd} generation S/Gs for these mechanisms. However, the greatest incidence of degradation still occurs in 1^{st} generation S/Gs compared to 2^{nd} generation S/Gs.

Table A-1 presents a summary of the degradation experience in 2^{nd} generation S/Gs.

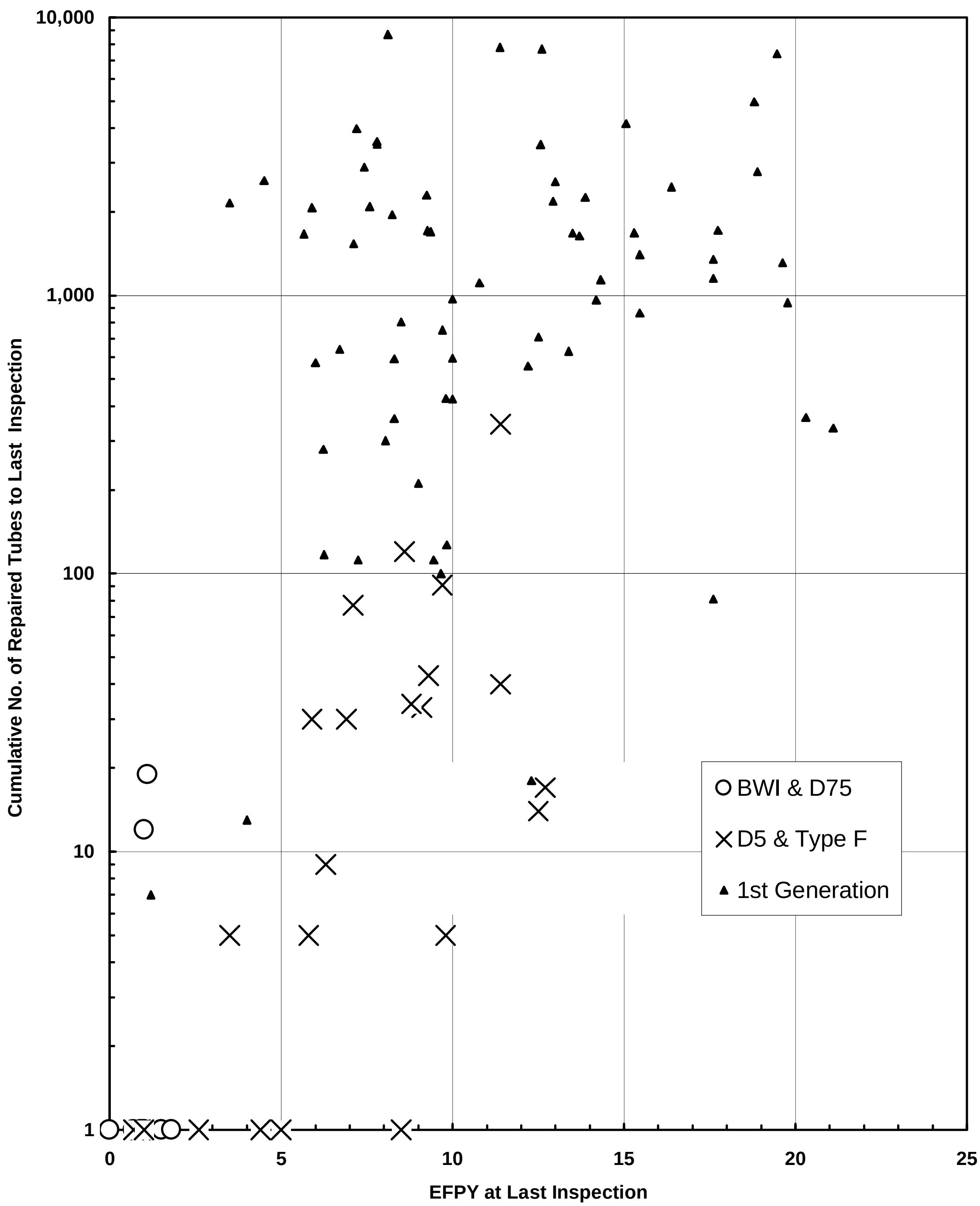

Figure A-1
Cumulative No. of Repaired Tubes to Last Inspection vs. EFPY at Last Inspection, 1st and 2nd Generation S/Gs at US Plants, All Mechanisms Except Other

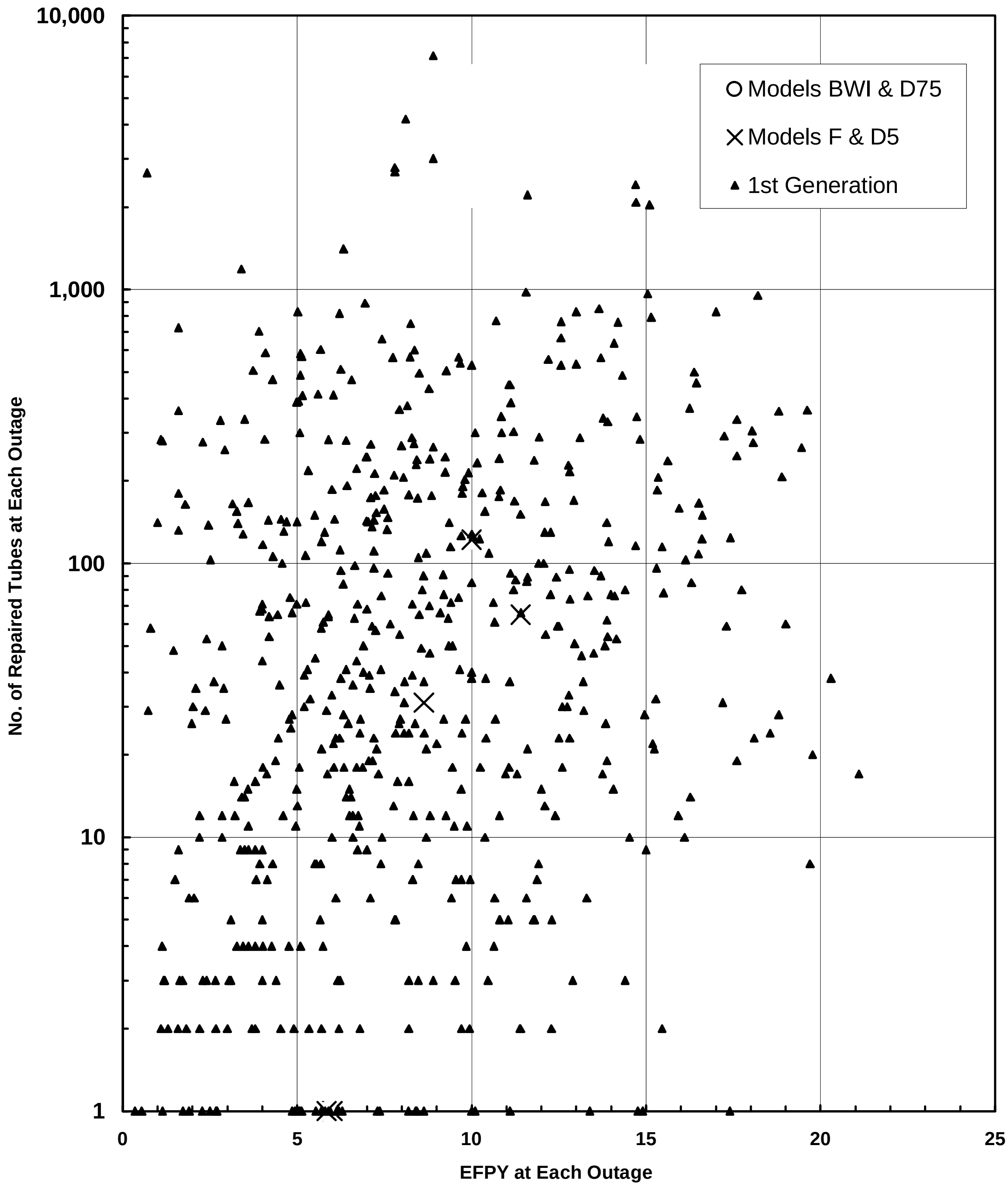

Figure A-2
No. of Repaired Tubes at Each Outage vs. EFPY at Each Outage, 1st and 2nd Generation S/Gs at US Plants, Mechanisms: IGA, SCC, Pitting, and Thinning

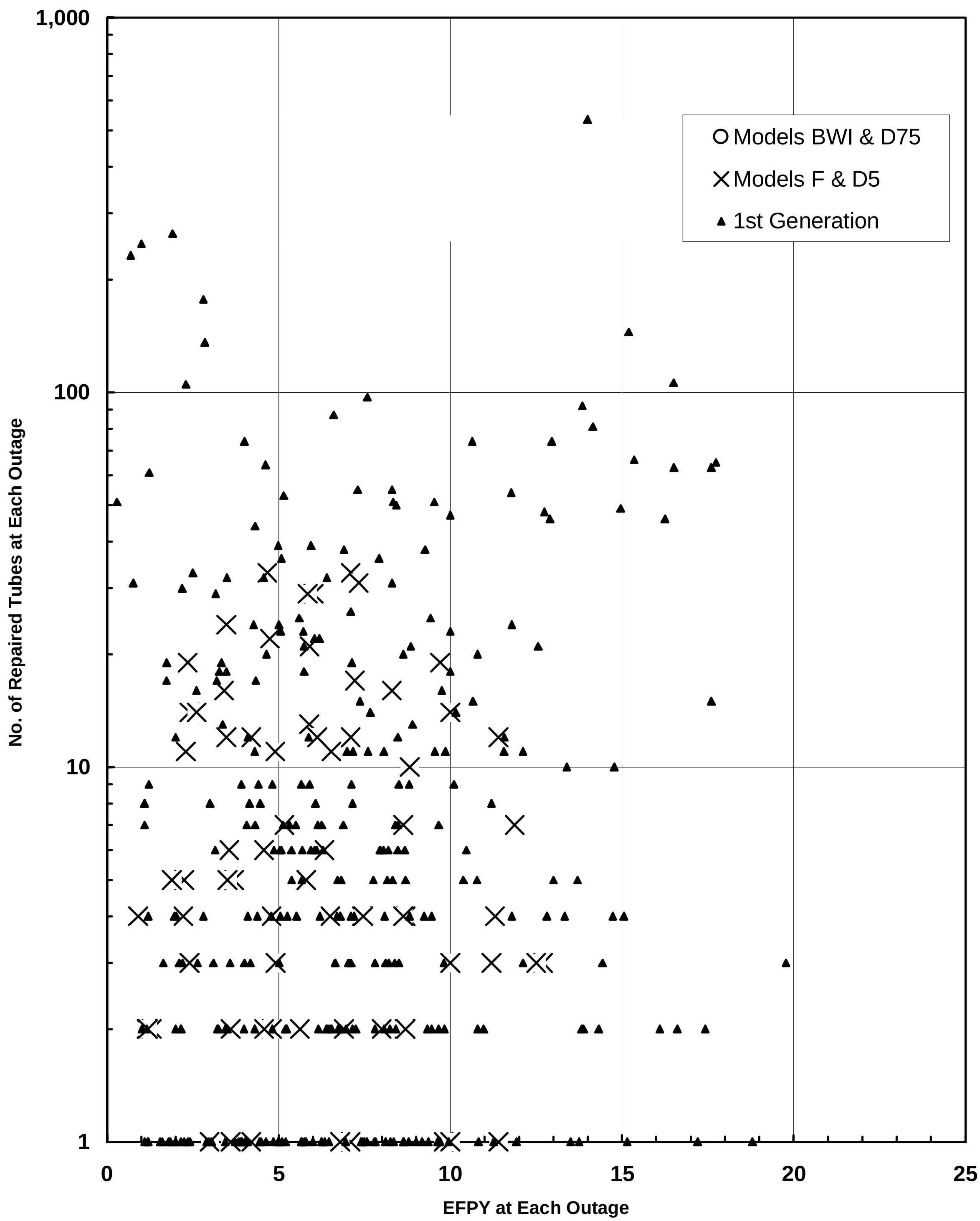

Figure A-3
No. of Repaired Tubes at Each Outage vs. EFPY at Each Outage, 1st and 2nd Generation S/Gs at US Plants, Mechanisms: Fatigue, Impingement, and Wear

Table A-1
Degradation Summary for 2nd Generation S/Gs.

Degradation Mechanism	Cumulative Number Of Repaired Tubes
SCC	1
Impingement	6
Preventative	88
Wear	468

The information in Table A-1 shows that wear is essentially the only degradation in 2nd generation S/Gs at this point in time.

A more detailed look at wear degradation in 2nd generation S/Gs is presented in Figure A-4, which presents the cumulative number of repaired tubes as a function of EFPY at each inspection. The data in Figure A-4 show that about half the 2nd generation S/Gs currently in service have wear degradation. However, about 30% of the plants without wear degradation have operated for less than two cycles. There is a wide variation in the number of repaired tubes between plants where wear degradation has occurred. Based on these data it does not appear feasible to develop a generic empirical correlation that can be used to predict the time to wear degradation on a plant specific basis. The approaches described in Section 2.4 can be used to predict the time to wear degradation.

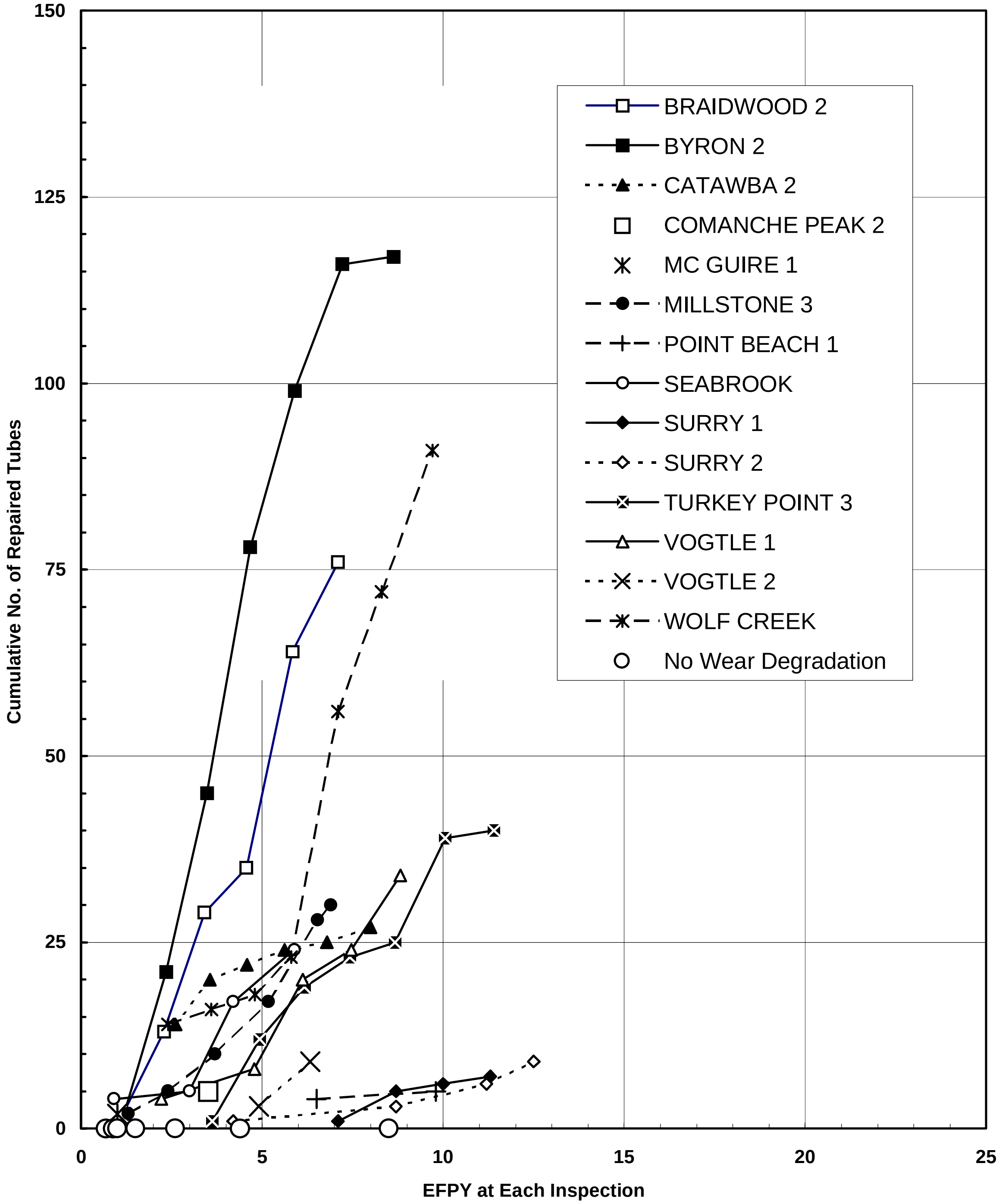

Figure A-4
Cumulative No. of Repaired Tubes vs. EFPY at Each Outage, 2nd Generation S/Gs at US Plants, Mechanisms: AVB Wear

B
AVB WEAR MODEL

To implement a PBI program for S/Gs it is necessary to have an accurate prediction of the time for the degradation level to reach approximately the CML. Two general classes of mechanisms must be considered when developing RI inspection programs for 2nd generation S/Gs. These include AVB wear and various corrosion mechanisms. As indicated earlier in this report, AVB wear has been detected in 2nd generation S/Gs, while no corrosion degradation has been detected to date. This appendix provides one method for predicting the time to reach the CML for AVB wear.

B.1 Summary of AVB Wear Model

The EPRI tube wear evaluation model for U-tube recirculating S/Gs is based on determining a set of wear parameters using the tube flow induced vibratory response [7]. The vibratory response depends on tube motion in the supports, clearances between the tubes and the supports and AVBs, and support reactions. Tube wear is computed using the computed wear parameters and experimental correlations for tube wear.

The flow velocity distribution in a S/G is calculated by the thermal hydraulic code ATHOS [10]. The finite element software ABAQUS [11] is used to perform the tube flow induced vibratory analysis. The finite element code is supplemented with simulation routines for the turbulence loading, fluid elastic effects and tube/support interaction.

The turbulence induced forces are simulated for a spatially correlated power spectral density function to represent the variation of forces along the tube length. The fluid elastic simulation is based on unsteady flow theory of fluid elastic vibration. The tube/support interaction is implemented by nonlinear elements consisting of clearances, contact stiffness, squeeze film stiffness and damping, and friction. The wear is proportional to the product of the tube support reaction force and sliding distance of the tube against the support. The tube wall thickness reduction varies at various locations of the wear scar and depends on the support geometry.

The remainder of this appendix describes the input needed to perform the wear evaluation using the ABAQUS and ATHOS software.

B.2 Data Required for AVB Wear Model

SEPARATOR DECK

Total Number of Steam Separators	=	
Available Flow Area Per Separator	=	in^2
Available Free Volume Inside Each Separator	=	in^3

SHELL AND SHROUD DIMENSIONS (Figure B-1)

Axial Distance from top of tubesheet (TTS) to Start of Shroud Expansion (ZEXP11)	=	in
Axial Distance from TTS to End of Shroud Expansion (ZEXP12)	=	in
Inner Radius at ZEXP12 (REXP12)	=	in
Shroud Metal Thickness	=	in
Axial Distance from TTS to Start of Shell Expansion (ZEXP21)	=	in
Inner Radius of Shell at ZEXP21 (REXP21)	=	in
Axial Distance from TTS to End of Shell Expansion (ZEXP22)	=	in
Inner Radius of Shell at ZEXP22 (REXP22)	=	in
Axial Distance from TTS to Bottom (i.e. Start) of Region 8(ZEXP13)	=	in
Radius of the Throat Region adjoining Region 8(REXP13)	=	in
Axial Distance from TTS to Start of the Throat Region adjoining Region 7(ZTHRT)	=	in
Radius Of Throat Region adjoining Region 7(RTHRT)	=	in

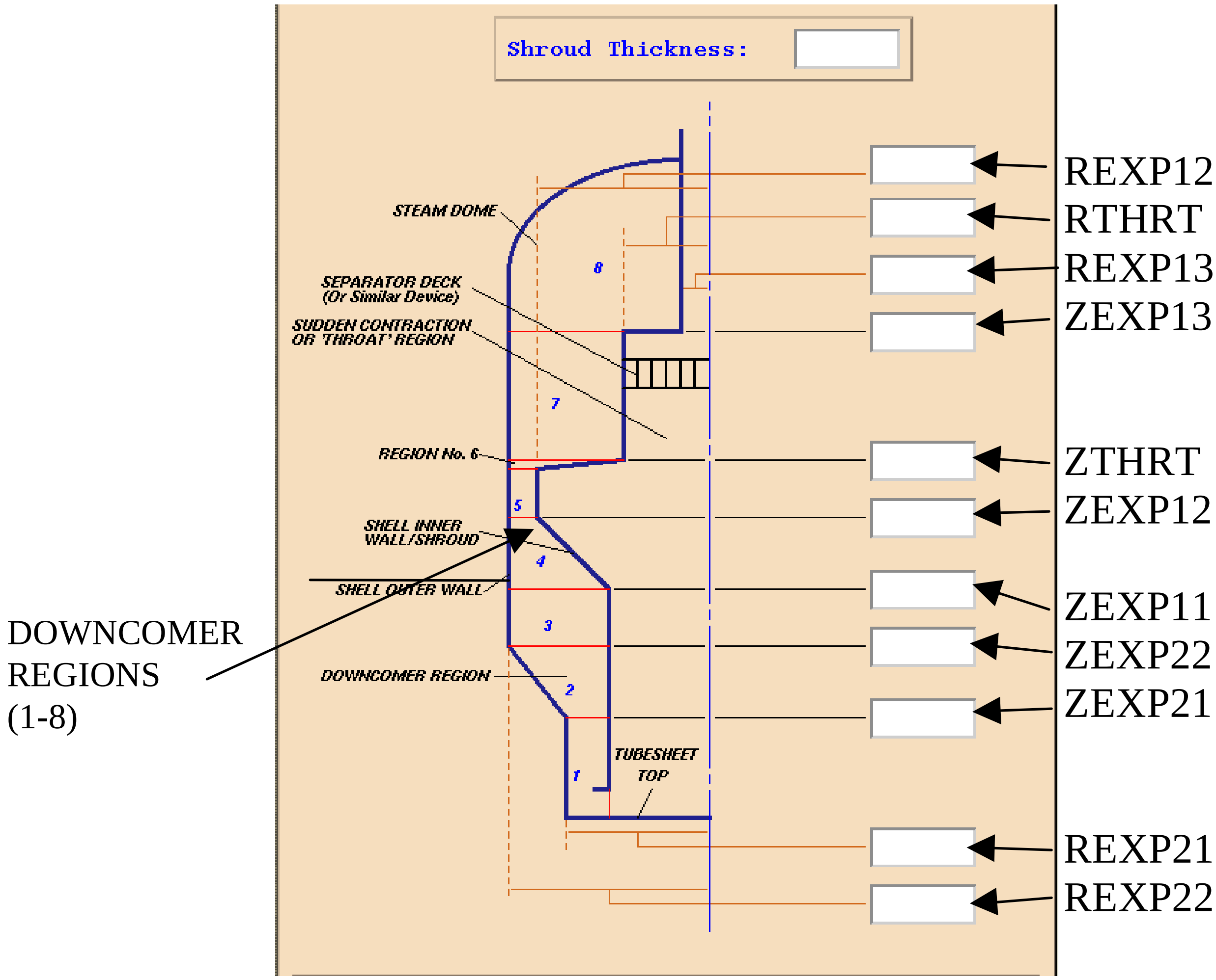

Figure B-1
Shell And Shroud Schematic

TUBE BUNDLE LAYOUT (Figure B-2)

Pitch Type(Choose One)	Triangular/Square	
Number of Rows in Tube Bundle	=	
Number of Lines/Columns in Tube Bundle	=	
Horizontal Tube Pitch (for U-bend region)	=	in
Vertical Tube Pitch	=	in
Angle of Vertical Tube Pitch(Choose One)	60 /90 deg	
Tube Inner Diameter	=	in
Tube Outer Diameter	=	in
Distance from end of Tube to Top of Tube Sheet	=	in
Row and Column Numbers of Plugged or Blocked Tubes (enter a pair)	=	
Row and Column Numbers of Tie Rods (enter a pair)	=	

For Every Row, Provide the Following Information (Figure B-2)

Row Number	=	
Line/Column Number of the First Tube (going from low to high line/column numbers)		=
Number of Tubes in a Row	=	
Length of the Horizontal Tube Span(for CE Systems)	=	in
Length of the Vertical Tube Span (Tube end to Bend Tangent)	=	in
Tube Ubend Radius(for non-CE systems)	=	in
Distance between Rows(DROWT)	=	in
Distance from Tubelane Center to Center-line of first row of tubes(DROW1)	=	in
Distance between Lines(DLINET)	=	in

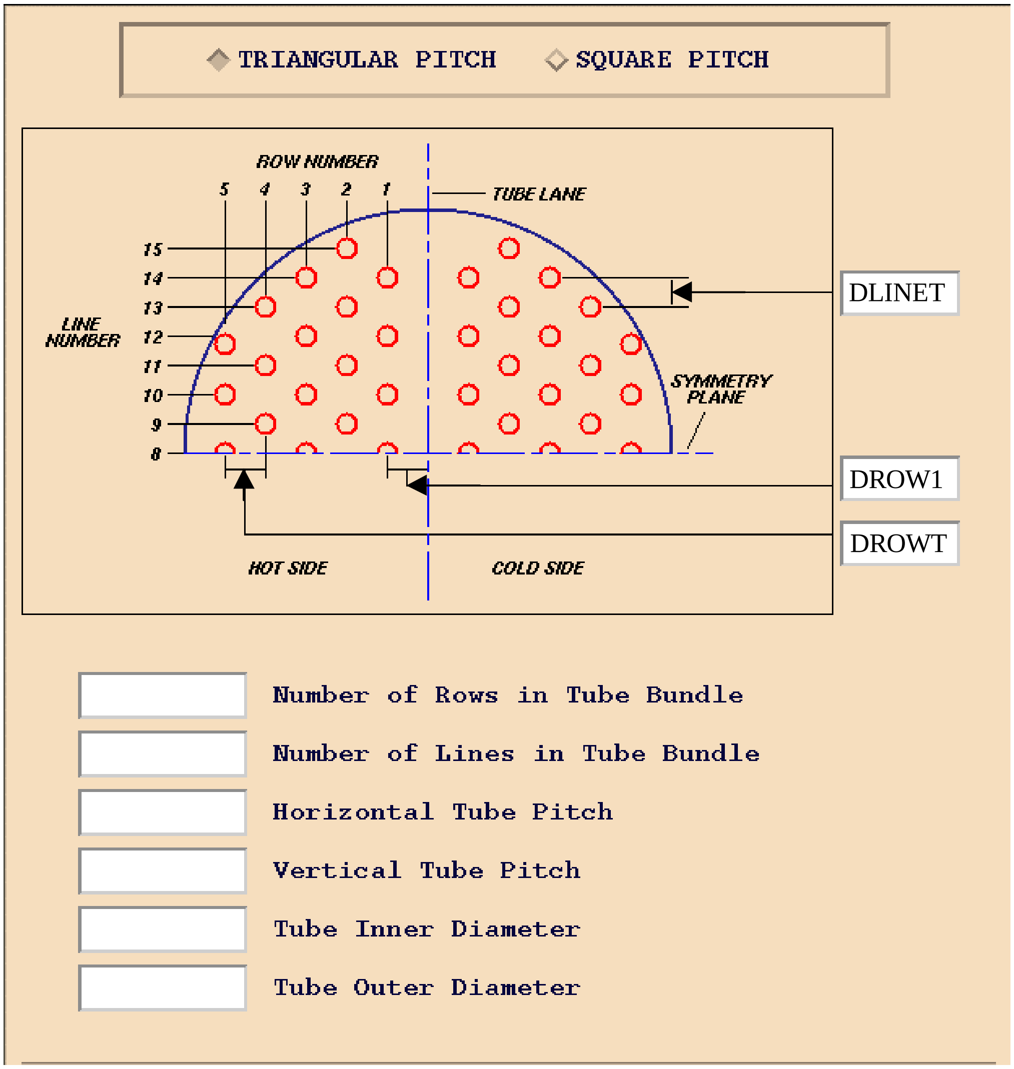

Figure B-2
Tube Bundle Schematic

VERTICAL BAFFLES (Provide the information only if applicable)

Number of Vertical Baffles	=	

For Every Vertical Baffle, Provide the Following Information:

Radius at Which Vertical Baffle is Located	=	in
Axial Distance from the TTS to the Bottom of the Baffle (Default = 0.0)	=	in
Axial Distance from the TTS to the Top of the Baffle	=	in
Type of Vertical Baffle(Choose One)	Hot/Cold/Full	

STAY CYLINDER/VERTICAL DIVIDER PLATE
(Provide the information only if applicable)

Axial Location (from the TS) of Stay Cylinder/VDP Top	=	in
Stay Cylinder Diameter	=	in
Vertical Divider Plate Thickness	=	in

IMPINGEMENT PLATE (Provide the information only if applicable)

Axial Location (from TS) of Impingement Plate Bottom	=	in
Axial Location (from TS) of Impingement Plate Top	=	in
Radius of the Outer Face of the Impingement Plate	=	in

DOWNCOMER INLET/OUTLET

Axial Distance from TTS to Bottom of Hot Side Downcomer Opening	=	in
Axial Distance from TTS to Top of Hot Side Downcomer Opening	=	in
Axial Distance from TTS to Bottom of Cold Side Downcomer Opening	=	in
Axial Distance from TTS to Top of Hot Side Downcomer Opening	=	in

DISTRIBUTION PLATES (Figure B-3) (Provide the information only if applicable)

Metal Thickness of Plate	=	in
Distance from TTS to the bottom of the Distribution Plate	=	in

NOTE: ATHOS allows for the distribution plate to have a total of 6(six) hole diameters corresponding to 6(six) regions. For example, if the distribution plate has 2(two) regions for both hot and cold side for a total of 4(four) regions, then RC1, RH1, RC2, RH2, DH1, DH2, DC1, DC2 have to be specified. The default values for the radius and hole diameters are 0.0.

Hole Diameter for region 1 on the cold side (DC1)	=	in
Inner Radius for region 1 on the cold side (RC1)	=	in
Hole Diameter for region 2 on the cold side (DC2)	=	in
Inner Radius for region 2 on the cold side (RC2)	=	in
Hole Diameter for region 3 on the cold side (DC3)	=	in
Inner Radius for region 3 on the cold side (RC3)	=	in
Hole Diameter for region 1 on the hot side (DH1)	=	in
Inner Radius for region 1 on the hot side (RH1)	=	in
Hole Diameter for region 2 on the hot side (DH2)	=	in
Inner Radius for region 2 on the hot side (RH2)	=	in
Hole Diameter for region 3 on the hot side (DH3)	=	in
Inner Radius for region 3 on the hot side (RH3)	=	in

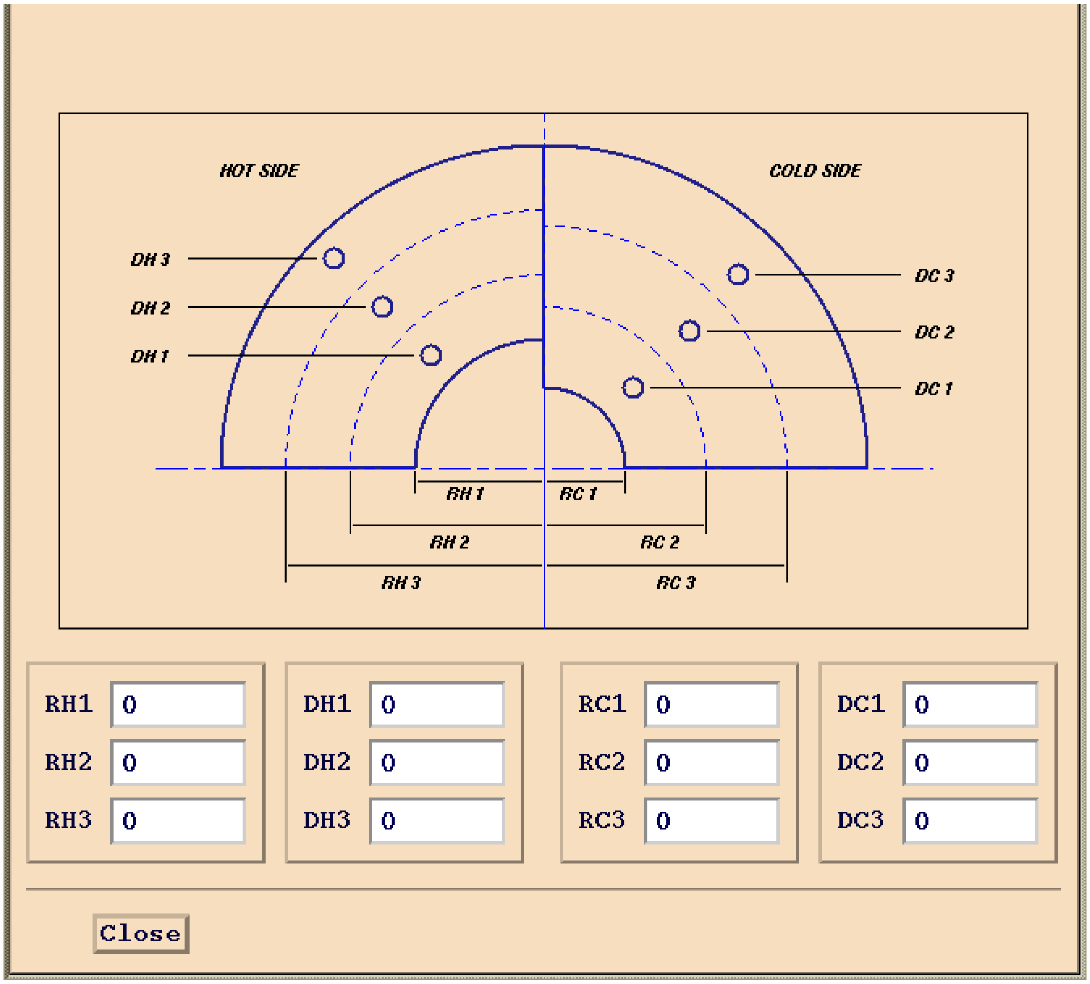

Figure B-3
Distribution Plate Schematic

TUBE SUPPORT PLATES

Total Number of Tube Support Plates (TSP)	=	

For Every Tube Support Plate Provide the Following Information:

Axial Distance from TTS to center of TSP	=	in
Inner Radius of TSP (if applicable)	=	in
Outer Radius of TSP	=	in

ANTI-VIBRATION BARS/FAN BARS (Figure B-4)

(Provide the following information if applicable)

Total Number of AVB Clusters	=	
Number of Bars in Each Cluster	=	

For Each Cluster Provide the Following Information:

Thickness of Each Bar	=	in
Width of Each Bar	=	in
Length of Each Individual Long Inclined Straight Section (AAVBL)	=	in
Axial Distance from TTS to the Bottom of Each Individual Long Inclined Section (AAVBH)	=	in
Angle to Vertical (in radians) of the Long Inclined Straight Section (AAVBA)	=	rad
Half-Length of the Short Horizontal Section (AAVBW)	=	in

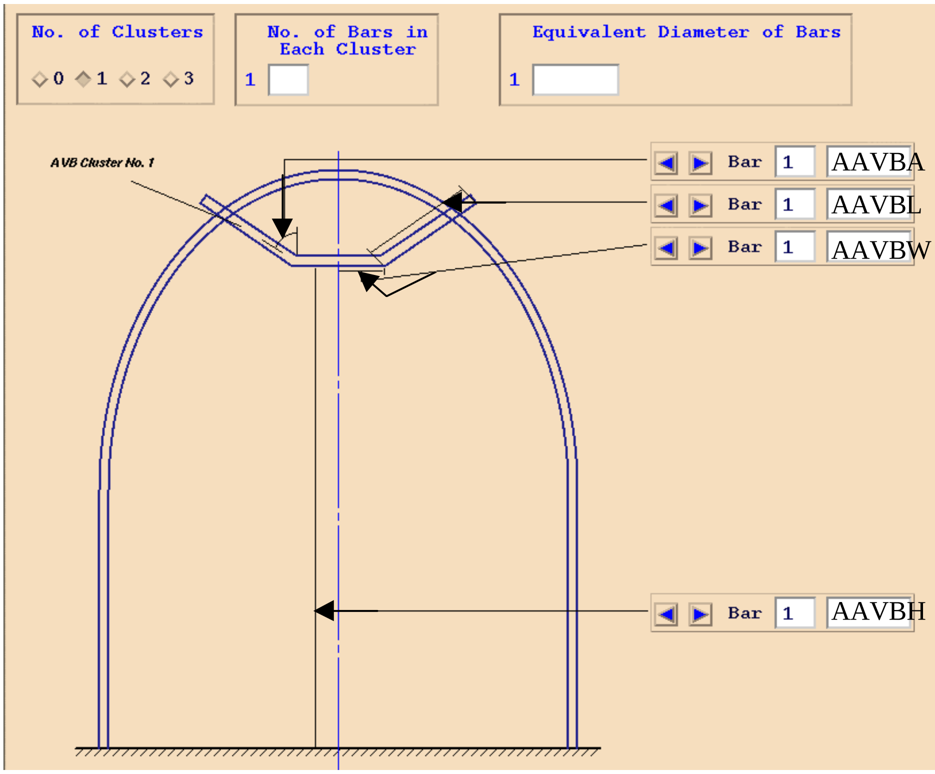

Figure B-4
AVB Schematic

BATWING VERTICAL BARS/FAN BARS (Figure B-5)
(Provide the following information if applicable)

Total Number of Clusters	=	

For Each Cluster Provide the Following Information:

Total Number of Bars in Each Cluster	=	
Thickness of each Bar	=	in
Width of each Bar	=	in

For Each Bar in the Cluster Provide the Following Information:

Angle (to Vertical) of the Bar (Normally = 0.0 rad)	=	rad
Distance from Each Vertical Bar Centerline from the Tube Free Lane		
Centerline (DISTX)	=	in
Axial Distance from TTS to the Bottom of Each Individual Vertical Bar (VBARH)	=	in
Length of Each Individual Vertical Bar (VBARL)	=	in

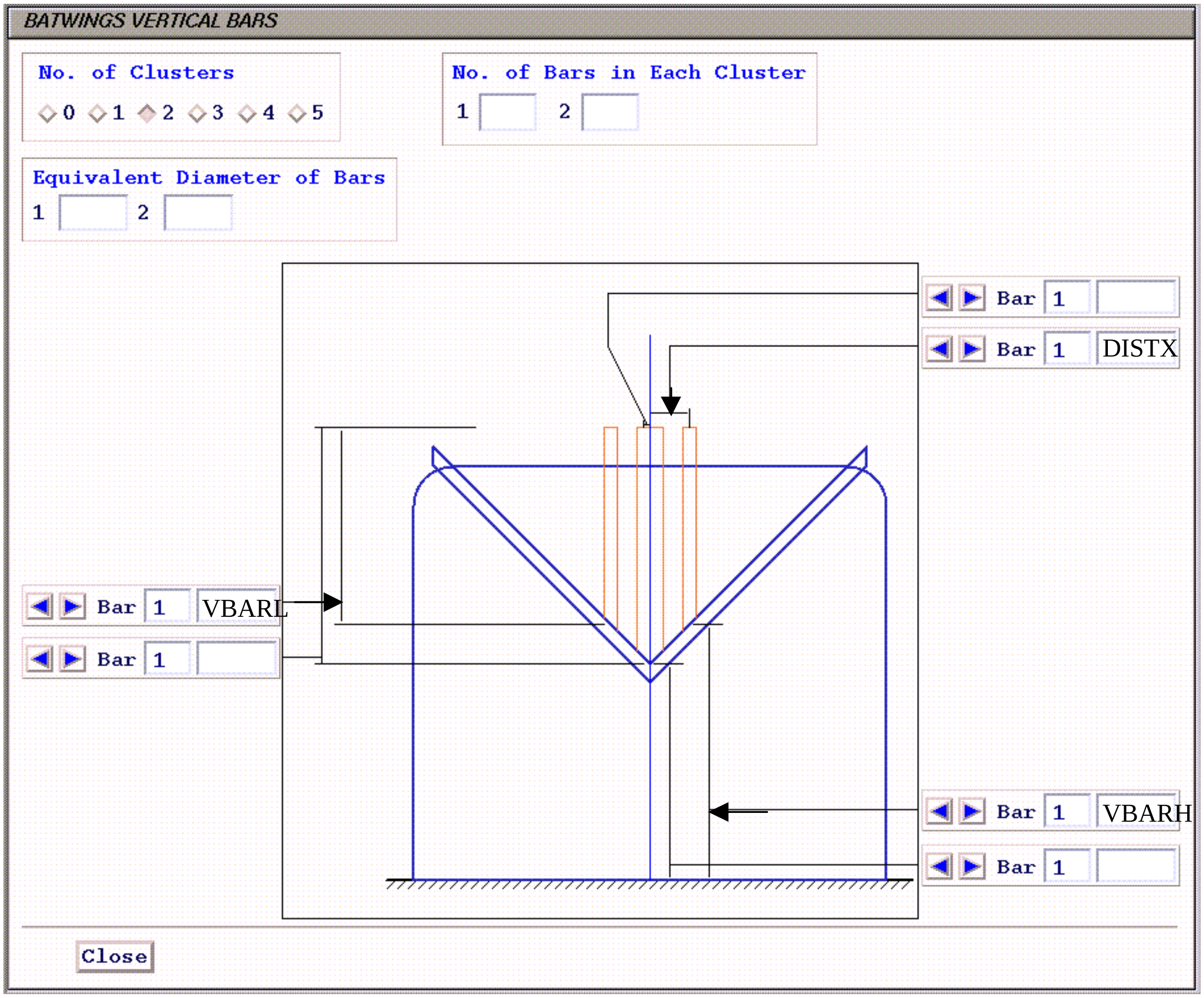

Figure B-5
Batwings Schematic

DETAILS REQUIRED REGARDING STEAM GENERATOR THERMAL HYDRAULICS

Hot Side Orifice (in the downcomer)	Y/N
Cold Side Orifice (in the downcomer)	Y/N
Hot Side Restrictor Plates	Y/N
Cold Side Restrictor Plates	Y/N

BOUNDARY CONDITIONS

Steam Dome Pressure (psi)	
Feedwater Flow Rate into Downcomer (gpm/lbm/s)	
Feedwater Flow Rate into Economizer (gpm/lbm/s)	
Feedwater Flow Rate into Lower Boundary (gpm/lbm/s)	
Feedwater Inlet Temperature (deg K)	
Downcomer Water Level (ft)	
Steam Exit Quality	
Primary Fluid Flow Rate (gpm/lbm/s)	
Fraction of Downcomer Feed Added to Hot Side	
Blowdown Fraction (% of Feedwater Flow Rate)	
Primary Fluid Inlet Temperature	
Fouling Heat Transfer Resistance (if available)	

ADDITIONAL INPUT REQUIREMENTS FOR EPRI STEAM GENERATOR VIBRATION/WEAR ANALYSIS

DISTRIBUTION PLATES

Tube hole shape	1) Drilled hole 2) Lattice Grid 3) Quatrefoil 4) Other (specify)
Tube hole geometry and dimensions	Provide sketch showing the dimensions of each distribution plate.
Tube hole radial clearance (nominal), in	

SUPPORTS IN STRAIGHT TUBE PORTION

Tube hole shape	1) Drilled hole 2) Lattice Grid 3) Quatrefoil 4) Other (specify)
Tube hole geometry and dimensions	Provide sketch showing the dimensions of each support plate.
Tube hole radial clearance (nominal), in	

SUPPORTS IN U-BEND PORTION (AVBs or BATWING BARS)

Anti-Vibration bars (or batwing) width, in	
Anti-Vibration bars (or batwing) thickness, in	
Anti-Vibration bar/tube (or batwing) radial clearance (nominal), in	
Tube/Anti-Vibration bar (or batwing) intersection angles measured from horizontal line passing through straight/U-bend transition point in hot leg, degrees.(see Figure).	
Anti-Vibration bar (or batwing) angles measured from horizontal in degrees (see Figure).	

BOUNDARY CONDITIONS FOR TUBES SUPPORTS

In some designs the AVBs are supported at the ends by support rings. Provide a sketch showing the AVBs with details of how they are supported with dimensions

Anti-Vibration bars (or batwing/fan bar) supports at the ends, i.e., how are the AVB or batwings supported in the steam generator—are they welded to support rings or attached in some other way.	

MATERIALS

Distribution plate material	
Tube support plate material	
Anti-Vibration bar (or batwing) material	
Tube material	

BASELINE ECT MEASUREMENTS

Tube wear depths, mils or %TW	

(1) Shape and dimensions of the hole shape in distribution plates or lattice grid supports.

(2) Nominal radial clearance from the design drawings. This is one-half of the difference in diameters of the hole and tube for drilled-hole type support (Dhole-Dtube)/2. For lattice grid supports the radial clearance is one-half of the difference between the distance between the parallel plates and tube diameter, (Distance between the parallel lattice grid plates—Tube Diameter)/2.

(3) Cross-section of antivibration bars (or batwings) The radial clearance is one-half of the difference between the distance between the AVBs on either side and diameter of the tube, (Distance between AVBs-Tube Diameter)/2.

(4) The location where the AVBs (or batwing bars) intersects the tube. This may be provided for each tube in the U-bend region as an angle measured from the transition between the straight portion in hot-leg and the U-bend portion.

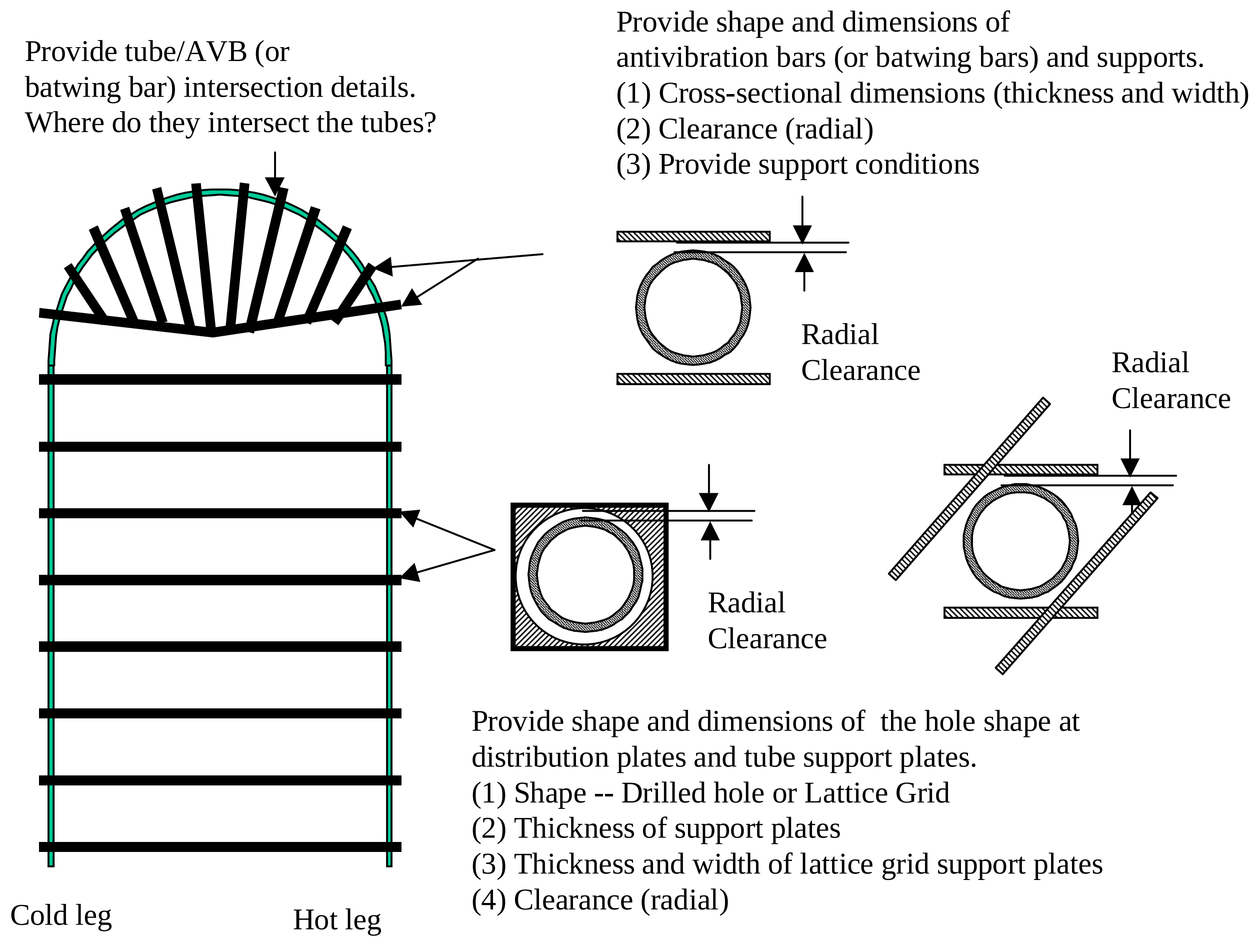

Figure B-6
Additional Details For Steam Generator Vibration/Wear Analysis

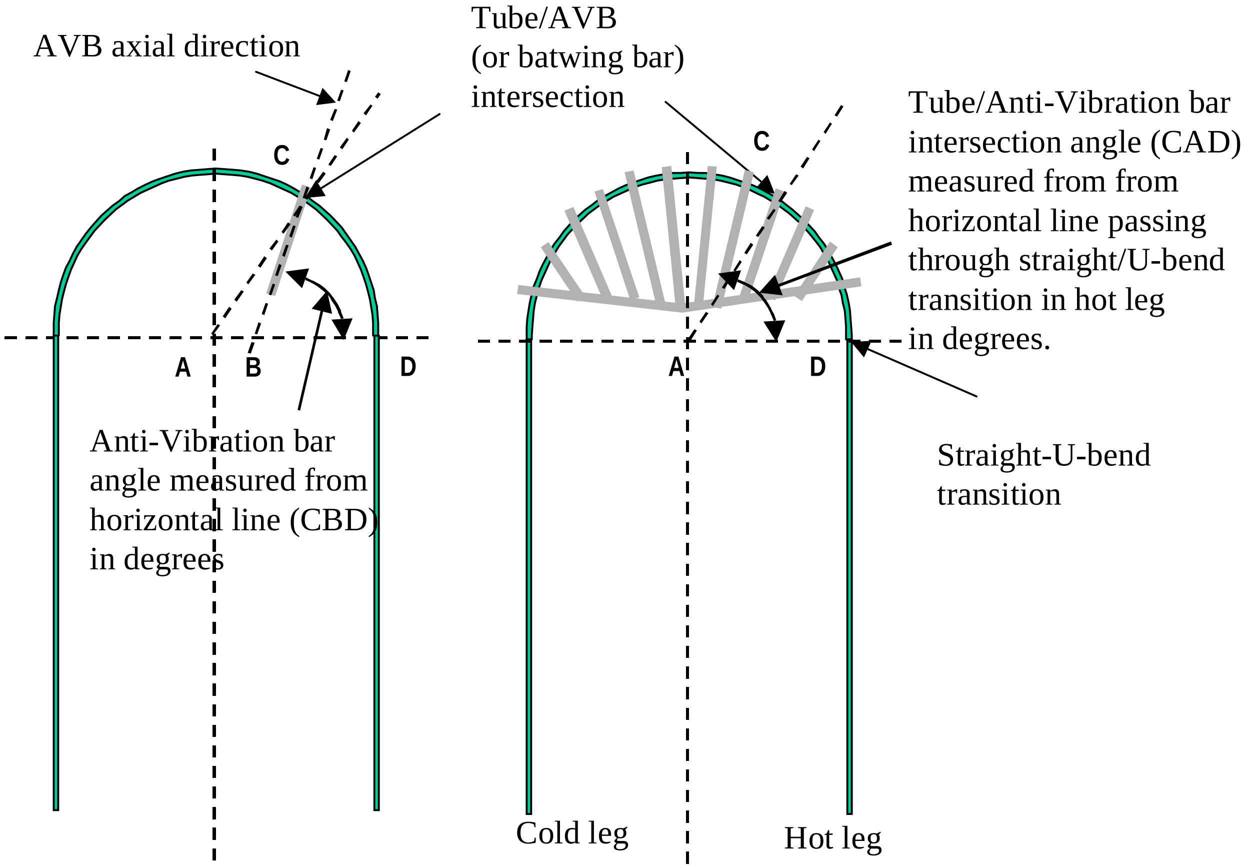

Figure B-7
Additional Details For Steam Generator Vibration/Wear Analysis

C
CORROSION MODEL

To implement a PBI program for S/Gs it is necessary to have an accurate prediction of the time for the degradation level to reach approximately the CML. Two general classes of mechanisms must be considered when developing RI inspection programs for 2nd generation S/Gs. These include AVB wear and various corrosion mechanisms. As indicated earlier in this report, AVB wear has been detected in 2nd generation S/Gs, while no corrosion degradation has been detected to date. This appendix provides guidelines for predicting the time to reach the CML for corrosion degradation in the absence of a lead plant.

C.1 Corrosion Model

The information in Tables 4-1 through 4-4 from TR-108501 [12] was used to obtain predictions of the time for corrosion degradation to reach levels corresponding to the CML. The predictions in [12] are based on experience with corrosion degradation in 1st generation S/G tubes adjusted for the changes made to 2nd generation S/Gs. These changes include use of: thermally treated (TT) tubes, stainless steel support plates with quatrefoil, lattice bar, or egg crate support configurations, and hydraulic expansion of the tubes into the tube sheet. The predictions in [12] were made for alloy 600 thermally treated tubes, and, for this study, are assumed to be applicable to 2nd generation S/Gs with alloy 690TT tubes.

The predictions were determined at a cumulative fraction of repaired tubes equal to 0.001. This cumulative fraction corresponds to approximately 3 to 8 tubes per S/G for most S/G designs. Based on past experience this number of repaired tubes would occur within the first one or two outages at which the corrosion degradation was first detected. In addition, there is usually some small fraction of the repaired tubes that have degradation levels between the repair limit and the SL.

Figure C-1 is a plot of the time to 0.001 cumulative fraction of repaired tubes as a function of T_{hot} for the three limiting corrosion mechanisms. Figure C-1 is used to predict the time to corrosion degradation when developing and implementing PBI programs for 2nd generation S/Gs.

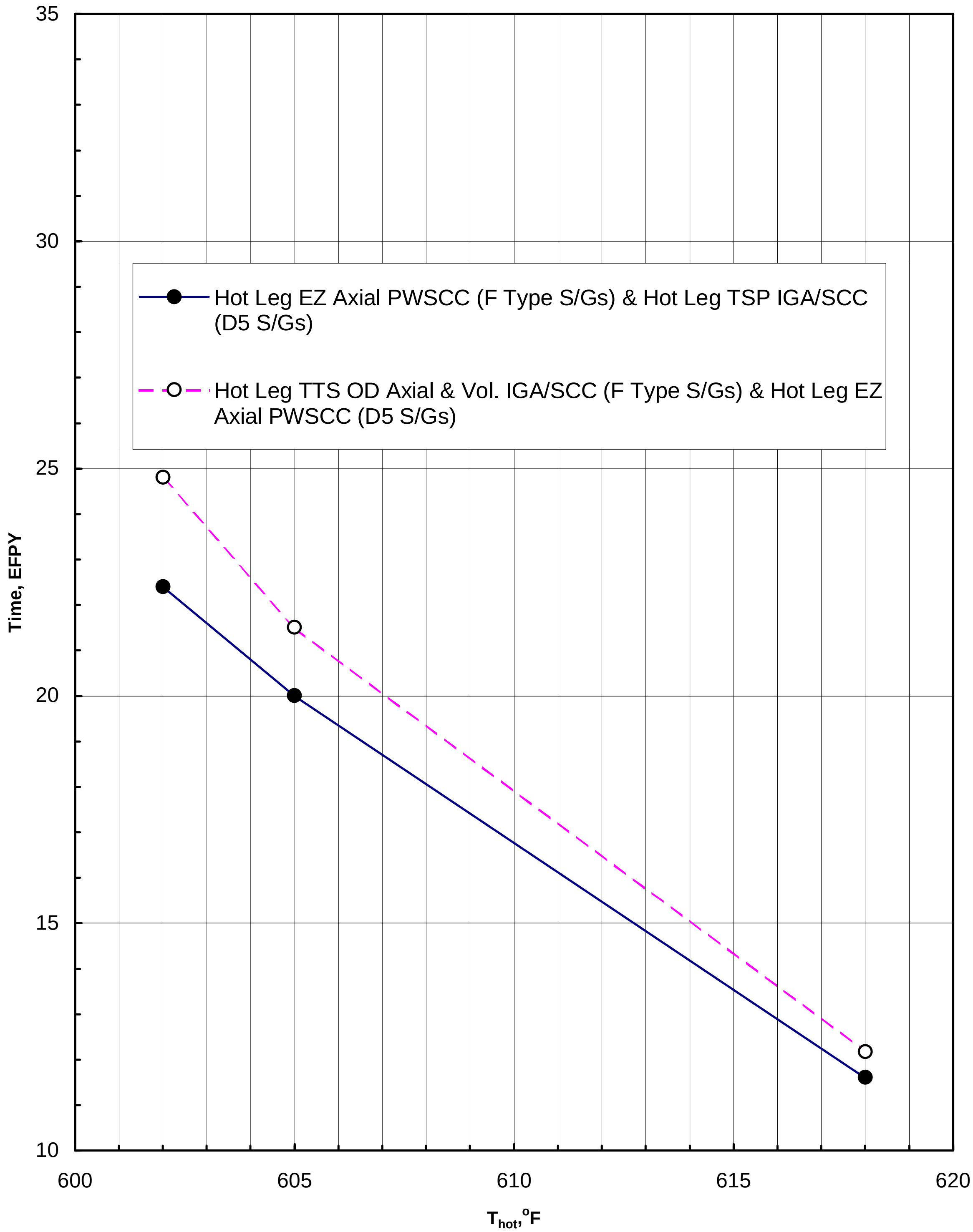

Figure C-1
Best Estimate Times to 0.1% Cumulative Number of Repaired Tubes as a Function of T_{hot}, 2^{nd} Generation S/Gs, Alloy 600TT Tubes

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