Risk Informed Inspection for Steam Generators

Volume 2: AVB Wear - A Case Study

Technical Report

Risk Informed Inspection for Steam Generators

Volume 2: AVB Wear – A Case Study

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REPORT SUMMARY

A steam generator (S/G) inspection program based on structural and leakage performance criteria will ensure adequate safety margins and may reduce inspection costs and personnel radiation exposure. This report, Volume 2 of *Risk Informed Inspection for Steam Generators*, provides evaluation procedures for defining S/G inspection intervals using risk-based evaluation procedures and performance criteria. It complements Volume 1 (EPRI report TR-114736-V1), previously published, which contains evaluation procedures for defining S/G inspection intervals using deterministic performance criteria.

Background

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. 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. 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 *PWR Steam Generator Examination Guidelines* (EPRI report TR-107569-V1R5). The first volume of EPRI report TR-114736-V1 developed deterministic performance criteria to extend inspection intervals. The second volume (EPRI report 1001406-V2) illustrates how a risk-based methodology can be employed to evaluate anti-vibration bar (AVB) wear degradation in second generation S/Gs.

Objective

To illustrate how risk-based methodology can be employed to develop inspection intervals for second generation S/Gs with AVB wear degradation.

Approach

The project team developed inspection intervals for S/Gs with AVB wear degradation based on determining the maximum operating interval where the risk during accident conditions does not exceed risk-based performance criteria for a distribution of degraded tubes. The team used risk-based evaluation procedures developed in *Steam Generator Integrity Risk Assessment* (EPRI report TR-107623-V1 and 2). The risk measures used in the evaluation are large early release frequency (LERF) and change in LERF (ΔLERF).

Results

The method and evaluation procedures in this report provide a technically sound, well-defined process for developing risk-based inspection programs that comply with structural and leakage performance criteria. Implementation of a risk-based inspection program ensures adequate safety

margins and could reduce inspection costs and personnel radiation exposure. Such a program may increase the inspection interval and add flexibility to inspection scheduling for first and 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*. Application of the risk-based evaluation procedure and performance criteria will have the greatest benefit for first or second generation S/Gs with degradation levels that may be in excess of levels allowed by deterministic performance criteria.

EPRI Perspective

Volume 1 of this report described procedures to use deterministic performance criteria to justify increased inspection intervals. In this approach, the length of the inspection interval is defined as the operating time where the degradation in any one tube would not exceed the degradation allowed by deterministic structural and leakage performance criteria. This approach works well for steam generators with either no degradation or with slow growth degradation mechanisms. Volume 2 demonstrates the application of risk-based performance criteria to determine a performance based inspection interval. The risk-based performance criteria can be applied to determine a performance based inspection interval when degradation levels are beyond those allowed by deterministic performance criteria. The risk-based evaluation procedures and performance criteria will provide the greatest benefit when applied to first and second generation S/Gs with relatively severe degradation levels. Application of the risk-based evaluation procedure was illustrated for tube wear at anti-vibration bar locations in a 2nd generation S/G.

The cost savings from increased 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. However, implementing performance based inspection intervals determined from risk evaluations will require additional costs for enhanced probabilistic risk assessment evaluations and associated licensing support.

Keywords

Nuclear steam generators
In-service inspection
Risk-informed in-service inspection
Risk-based in-service inspection

ABSTRACT

This report uses previously developed risk 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 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 performance criteria ensures adequate safety margins are maintained and, at the same time, adds flexibility to inspection scheduling, and reduces inspection costs and personnel radiation exposure.

The risk-based evaluation procedures and performance criteria will provide the greatest benefit when applied to first (1^{st}) and second (2^{nd}) generation S/Gs with degraded tubes, where deterministic performance criteria cannot be satisfied for a desired inspection interval.

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1
INTRODUCTION

1.1 Background

First (1^{st}) generation S/Gs are S/Gs that up until several years ago were installed as original equipment in pressurized water reactors (PWRs). Service experience shows that many tubes in 1^{st} 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 1^{st} generation S/Gs was large enough that the S/Gs were replaced or will be replaced over the next several years.

Second (2^{nd}) generation S/Gs have been designed to reduce inservice degradation, and are being used as original equipment for newer plants, and as replacements for plants with 1^{st} generation S/Gs. Available service experience at PWRs in the United States indicates that 2^{nd} generation S/Gs have significantly less tube degradation compared to 1^{st} generation S/Gs. To date, the only significant degradation detected in 2^{nd} generation S/Gs is wear, which has occurred in some 2^{nd} generation S/Gs. Some 2^{nd} generation S/Gs have operated over ten effective full power years (EFPY) without tube degradation.

Because the degradation in 2^{nd} generation S/Gs is relatively low there is the potential to reduce the frequency and number of tube inspections for 2^{nd} 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 2^{nd} generation S/Gs compared to requirements in current plant Technical Specifications (T/S) and Chapter 3 of the PWR Steam Generator Examination Guidelines (ISI Guidelines) [2].

Recently, deterministic, performance based evaluation procedures and acceptance criteria have been defined for 2^{nd} generation S/Gs with relatively low levels of wear degradation. These deterministic evaluation procedures and criteria are described in Risk-Informed Inspection for Steam Generators: Volume 1: Deterministic Performance Based Criteria [3]. Volume 1 [3] provides guidelines for developing a performance based inspection program for S/Gs, including defining the length of the inspection interval, inspection sample sizes, loose parts prevention and monitoring, and in-situ testing.

As degradation levels increase it is possible that the deterministic performance criteria may not be satisfied for the desired inspection interval. In this instance, risk-based performance evaluation procedures and criteria can be employed to demonstrate adequate margins. Risk-based evaluation procedures have been used previously to determine inspection intervals for 1^{st} generation S/Gs for corrosion degradation. Guidelines for performing risk-based evaluations, including an example application for corrosion degradation, have been developed previously and are described in Steam Generator Tube Integrity Risk Assessment: Volumes 1[4] and 2 [5].

1.2 Objectives

The purpose of the work described in this report is to illustrate how previously defined risk-based methodology [4] can be employed to evaluate AVB wear degradation in 2nd generation S/Gs. Implementing a risk-based performance methodology would allow inspection intervals to extend beyond those recently defined by deterministic performance criteria [3]. The risk-based inspection interval is the maximum operating interval for which risk-based performance criteria are satisfied. Using risk-based performance criteria 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 risk-based performance criteria would ensure adequate safety margins are maintained, provide flexibility in defining inspection intervals, 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 risk during accident conditions does not exceed risk-based performance criteria for a distribution of degraded tubes. The work described in this report uses risk-based evaluation procedures and performance criteria from previously developed industry [4] and regulatory guidelines [6] to illustrate determination of a risk-based inspection interval for AVB wear degradation in 2nd generation S/Gs.

The risk measures used in the evaluation are large early release frequency (LERF) and change in LERF (ΔLERF). LERF is "the frequency of those accidents leading to significant, unmitigated releases from containment in a time frame prior to effective evacuation of the close-in population such that there is a potential for early health effects" [6].

Regulatory guidelines [6] require consideration and analysis for risk-based regulation that is larger in scope than the methodology [4,5] used in this study. The regulatory guidelines [6] addresses issues about PRA quality, required uncertainty analysis, defense-in-depth, and blended deterministic and probabilistic analysis. These items are outside the scope of this study and are not addressed in this report. Any plant-specific use of the methodology [4,5] should be in the context of a comprehensive risk assessment, which must address these issues before being used for regulatory submittals.

1.4 Implementation

Implementation of risk-based inspection (RBI) intervals will have its greatest benefit for 1st and 2nd generation S/Gs where degradation has been detected, and there are relatively high levels of degradation that may exceed deterministic performance criteria. Implementation of risk-based evaluation procedures should be most effective when they are employed to avoid mid-cycle inspections, or to predict the maximum operating interval for which the risk-based performance criteria are satisfied and add flexibility to inspection scheduling.

An important complement to implementation of any performance based inspection 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 applicable 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 any performance based inspection program. If loose parts are detected, the contribution to risk from loose parts must be determined and included in the risk evaluation.

1.5 Report Organization

Section 2 of this report is a summary of the methodology used to determine inspection intervals for risk-based inspection programs. Guidelines for developing performance based inspection (PBI) programs are presented in Section 3 for both deterministic and risk-based evaluation procedures. Section 4 provides an example case study using these guidelines for a 2nd generation S/G. 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 summary of the calculations performed in the case study to determine the probability that S/G tube failure occurs prior to piping failure during accident conditions. Appendix B provides a summary of the evaluation performed in the case study to determine the large early release frequency (LERF) and change in LERF associated with the distribution of degraded tubes for various inspection intervals. Appendix C contains the burst pressure and leak rate data used in the Monte Carlo analysis to determine degradation distributions for the case study.

2
SUMMARY OF INSPECTION INTERVAL DETERMINATION

Determination of a risk-based inspection interval is defined by the operating time where an acceptable level of risk is maintained during postulated accident conditions for a distribution of degraded tubes. This determination involves two steps. The first is to specify the desired inspection interval and predict the degradation distribution at the end of the interval. The second step is to calculate the risk at accident conditions for the degradation distribution, and determine if the risk-based performance criteria are satisfied at the end of the specified interval. This can be done for a single interval or a series of intervals. Using a series of intervals provides information to define the maximum allowable inspection interval for which the performance criteria are satisfied.

The remainder of this chapter describes the risk-based performance criteria and approach used to determine the risk-based inspection interval.

2.1 Performance Criteria for Risk-Based Evaluations

2.1.1 Structural Risk Performance Criteria

The risk measures used in defining the inspection interval are large early release frequency (LERF) and change in LERF (ΔLERF). LERF is "the frequency of those accidents leading to significant, unmitigated releases from containment in a time frame prior to effective evacuation of the close-in population such that there is a potential for early health effects" [6].

The risk-based performance criteria are based on the guidelines in [6] and are used to evaluate applications for changes in a plant's licensing basis. The criteria are explained as follows in Reference [6]:

> "If the application clearly can be shown to result in a decrease in LERF, the change will be considered to have satisfied the relevant principle of risk-informed regulation with respect to LERF.
>
> When the calculated increase in LERF is very small, which is taken as being less than 10^{-7} per reactor year, the change will be considered regardless of whether there is a calculation of the total LERF. While there is no requirement to calculate the total LERF, if there is an indication that the LERF may be considerably higher than 10^{-5} per reactor year, the focus should be on finding ways to decrease rather than increase it. Such an indication would result, for example, if (1) the contribution to LERF calculated from a

limited scope analysis, such as the IPE or the IPEEE, significantly exceeds 10^{-5}, (2) a potential vulnerability has been identified from a margins-type analysis, or (3) historical experience at the plant in question has indicated a potential safety concern.

When the calculated increase in LERF is in the range of 10^{-7} per reactor year to 10^{-6} per reactor year, applications will be considered only if it can be reasonably shown that the total LERF is less than 10^{-5} per reactor year.

Applications that result in increases to LERF above 10^{-6} per reactor year would not normally be considered."

The risk-based criteria used in this study to assess tube integrity are consistent with [6], and are:

1. A distribution of degraded S/G tubes has an unacceptable margin against tube rupture for accident conditions when ΔLERF is greater than 1E-6 per reactor-year.
2. A distribution of degraded S/G tubes has a marginally acceptable margin against tube rupture for accident conditions when LERF is less than 1E-5 per reactor-year and ΔLERF is between 1E-6 and 1E-7 per reactor-year.
3. A distribution of degraded S/G tubes has an acceptable margin against tube rupture for accident conditions when LERF is less than 1E-5 per reactor-year and ΔLERF is less than 1E-7 per reactor-year.

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).

2.1.4 Primary to Secondary Leakage Monitoring

The guidelines in [7] provide an effective program for monitoring primary to secondary leakage. Implementing the operational actions described in the guidelines [7] ensure that the performance criteria specified in 2.1.2 and 2.1.3 are met.

2.2 Determination of the Inspection Interval

Determination of the risk-based inspection interval has several components. The first is to identify the event sequences that are initiated by or lead to steam generator tube rupture, and determine the frequency of these sequences. The second is the determination of the pressure and temperature time history for each of the sequences. The third is to predict the distribution of degraded tubes at the end of the desired inspection interval. Fourth, an analysis is performed to determine the probability that S/G tube rupture occurs prior to failure of the piping in the flow path from the vessel hot leg to the S/G inlet plenum. Failure of this piping will depressurize the primary side of the S/G tubes and preclude tube failure. Finally, LERF and ΔLERF are computed to determine if the performance criteria are maintained during the defined inspection interval for the degradation distribution.

The remainder of this section provides a summary for each of the aspects used in the risk-based evaluation of the inspection interval. This information was obtained from [4], which provides detailed risk-based evaluation procedures for degraded S/G tubes. An illustrative application of these steps for AVB wear degradation is presented in Section 4.

The information presented in this chapter is based on conditions representative of a Westinghouse 4-loop PWR. Plant specific evaluations using the guidelines in [4] are required for individual plant and S/G assessments.

2.2.1 Identify Event Sequences and Frequencies

Determination of the sequences and frequencies of events initiated by or leading to tube rupture consists of two steps. The first step defines the events and conditions that can lead to S/G tube rupture or that can be initiated by S/G tube rupture. The second step considers the actions that can be taken to mitigate events initiated by or leading to tube rupture. The combination of these two steps defines the event sequences initiated by or leading to tube rupture and the frequency of these sequences.

2.2.1.1 Selection of Accident Sequences

The purpose of this step is to identify the accident sequences that either are initiated by or lead to S/G tube rupture. The results from the selection of accident sequences are used as the basis to assess the failure potential of pumps and valves, and identify the various thermal hydraulic (T/H) phenomena that contribute to the thermal challenge of the tubes. The results are used to construct Accident Progression Trees (APETS).

The selection of accident sequences is described in detail in Section 2 of [4]. The remainder of this section summarizes some of the major aspects of event sequence identification.

To complete this step, the plant probabilistic risk assessment (PRA), individual plant examinations (IPEs), and individual plant examination of external events (IPEEE) are used. In many instances the plant PRAs, IPEs and IPEEEs initially were not developed for risk assessments of S/G tube degradation. Consequently, the modeling data and assumptions originally used will have to be reviewed and updated to ensure the PRAs, IPEs and IPEEEs capture the sequences that either are initiated by or lead to S/G tube rupture.

The results from previous work [4,5] provide information that can be used to focus the updating of the PRAs, IPEs and IPEEEs. These studies [4,5] indicate that containment bypass frequency is the main contributor to LERF, and the flaw-related LERF increments come principally from the following types of challenges:

1. Spontaneous steam generator tube rupture (SGTR) initiators, with resultant core damage.
2. Steam-side depressurization events or anticipated transient without scram (ATWS) events, with resultant core damage, that may induce tube ruptures because of increased differential pressure across the tubes.
3. Core damage accidents due to other causes, during which flawed tubes are induced to fail either by increased pressure differentials at normal temperatures (caused by, for example, operator depressurization of the steam side or by stuck-open main steam safety valves), or at elevated temperatures following core heat-up.

2.2.1.2 Human Reliability Assessment of Recovery Actions

The key to assessing the risk associated with the failure of S/G tubes is determination of the probability that tube failure will occur prior to the failure of piping in the flow path from the vessel hot leg to the S/G inlet plenum. Because timing is an important aspect of the risk evaluation, human reliability assessment (HRA) of recovery actions is an important consideration in S/G risk assessment.

Many times PRAs do not credit operator action. In most PRAs, operator actions are conservatively modeled assuming no control or recovery action is taken. These assumptions simplify the risk assessment, but provide no systematic way to measure the risk impact of actions taken to protect the degraded tubes from accident challenges. The HRA methodology can address time-phased actions that effect steam generator tube integrity through control of secondary pressure, recovery of feed water sources, and recovery of primary makeup systems. HRA is described in detail in Section 3 of [4].

Part of this effort will include initial T/H computations to determine when in the event sequence the operator has the opportunity to mitigate the effects of the event. This information will help define potential operator actions and establish event frequencies. The T/H computational method is summarized in Section 2.2.2.

The results from the HRA are used to construct Expanded Operator Action Trees (EOATS). The EOATS consider the various operator actions associated with maintaining secondary side integrity while attempting to avert both core damage and thermal challenge to the steam generator tubes.

2.2.1.3 Summary of Accident Sequence and Frequency Assessments

The results from the selection of accident sequences described in Section 2.2.1.1 are used as the basis to assess the failure potential of pumps and valves, and identify the various T/H phenomena that contribute to the thermal challenge of the tubes. The results are used to construct Accident Progression Trees (APETS).

The results from the HRA described in Section 2.2.1.2 are used to construct Expanded Operator Action Trees (EOATs). The EOATs consider the various operator actions associated with maintaining secondary side integrity while attempting to avert both core damage and thermal challenge to the steam generator tubes.

Information flows from the EOATs to the to the APETs to characterize the frequency at which the various identified accident sequences either initiate or lead to S/G tube rupture. Section 7 of [4] describes the procedure to combine the EOATs and APETs.

The frequencies are reviewed and a screening process is used to determine those sequences that will have higher relative contribution to tube rupture. These transients are selected for further analysis as described in the following sections.

2.2.2 Thermal Hydraulic Analysis

The Modular Accident Analysis Program (MAAP) is used to simulate plant transient behavior for various severe accident sequences that may lead to S/G tube rupture. The MAAP model consists of two loops, one of which contains the pressurizer. In this study, thermal-hydraulic conditions in the two loops differ partly because of surge line flows to the pressurizer. More significant differences between loops are caused in some sequences by loop seal clearing (empties of water) in one of the cold legs, secondary side depressurization in one of the steam generators, or both. The MAAP model simulates forced and buoyancy-driven flows of hot gasses from the core to the hot legs and steam generator tubes, and forced flow through the surge line when a relief or safety valve opens.

MAAP is used to investigate the timing and choice of operator actions, the effects of equipment unavailability, and to calculate the pressures and temperatures as functions of time during the transient. The pressure and temperature time histories are then used to predict the potential for hot leg, surge line, and S/G tube failure using Larson-Miller correlations for creep rupture. Once hot leg or surge line failure occurs the primary system depressurizes rapidly and tube failure is precluded.

Sections 4.1.6 and 4.1.7 in [4] outline a series of thermal-hydraulic calculations that can be performed with the MAAP code to investigate the importance of thermal-hydraulic uncertainties affecting the likelihood of temperature induced S/G tube rupture (TISGTR). This is done for each of the sequences by varying certain input parameters to the phenomenological models. The most important thermal-hydraulic uncertainties are associated with the effectiveness of radiation heat transfer in the hot leg, the assumed flow pattern in the steam generators, and the degree of mixing between cold and hot gasses in the inlet plenum of the steam generator.

Sections 4 and 6 of [4] provide additional description for the MAAP Code and its application for investigating thermally-induced steam generator tube rupture.

2.2.3 Degradation Distribution

2.2.3.1 Computational Procedure

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 a degradation condition where the risk-based performance criteria listed in Section 2.1 are just satisfied. The degradation distribution at the end of the interval (EOI) is the distribution at the BOI adjusted for degradation growth during the interval, and NDE and analyst uncertainty.

The degradation distribution at BOI is the distribution of the values of the NDE measurement parameter obtained from the inspection results, adjusted for the probability of detecting defects, and excluding any tube repairs made prior to restart. 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 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 degraded tubes at the EOI. The EPRI software STEIN [8] can be used to perform the Monte Carlo sampling and predict the number of degraded tubes as a function of values of the NDE measurement parameter at the end of any specified operating interval. A trial and error procedure can be used to determine the maximum operating interval for which the risk for the EOI distribution of degraded tubes satisfies the performance criteria.

Because the degradation predicted by STEIN is distributed, there will be fractions of tubes in the distribution tail. STEIN integrates the tail of the degradation distribution at EOI back from the maximum value of the NDE measurement parameter in the distribution until the sum of the fractional tubes is equal first to 0.3 and then to 0.7. This conditioned distribution of the values of the NDE measurement parameter is used to compute the probability of tube rupture and assess compliance with the performance criteria.

2.2.3.2 Data Sources for Predicting Degradation Distributions

Section 2.4 of [3] described three approaches for predicting AVB wear degradation when determining deterministic, performance based inspection intervals. These included the lead plant, plant specific data, and the analytical approaches.

As indicated in Section 3.1 of [3] any of the applicable approaches could be used to predict the time for the limiting tube to reach the condition monitoring limit (CML). The CML is the value of the NDE measurement parameter corresponding to the deterministic structural performance criteria adjusted for the NDE uncertainty. The time to reach the CML then is used to define the initial deterministic performance based inspection interval. After the initial inspection, determination of the following inspection intervals essentially is based on plant specific inspection results.

In general, the risk at degradation levels near the CML is quite small, and the risk-based performance criteria likely would be satisfied with significant margin. In addition, risk is determined based on the degradation distribution, rather than the limiting tube. Consequently, the most likely application of risk-based evaluations is for degradation levels beyond the CML.

Either of the three approaches can be used for implementation of a risk-based inspection program. When plant-specific degradation has been detected, the plant specific data approach will use degradation growth rate measured in previous operating cycles to predict degradation growth for future operating cycles. If future operating cycles are short, the growth rate distribution obtained from the previous operating cycle should be a reliable predictor for future growth rates. However, as the future inspection intervals are lengthened beyond one or two cycles the projected growth rates will be more uncertain. In this instance, care should be taken to ensure that the projected growth rates are defined with a reasonable amount of conservatism.

The lead plant and analytical approaches also may play a role in predicting degradation distributions relative to risk evaluation for AVB wear degradation. For example, the lead plant approach could be used when degradation has been detected at the trailing plant, but there is not enough data to establish accurate degradation growth rates. In this instance, growth rate data from an available lead plant could be used to predict EOI degradation distributions at the trailing plant based on the BOI distribution at the trailing plant. When using the lead plant approach, an evaluation must be made to confirm that the tube essential variables (e.g., denting, deposits, tube geometry changes, signal characteristics) at the trailing plant are similar to the tube essential variables at the lead plant.

Similarly, the analytical model approach can be used when degradation has been detected at a plant, but there is not enough data to establish accurate degradation growth rate data. In the absence of a lead plant, the analytical model can be used to predict EOI degradation distributions. In this instance, the analytical model would be bench marked to the available plant specific service data. The analytical model also can be employed when plant specific growth rate data are available. In this case, the model can be used to project the distribution to the EOI, and confirm the distributions predicted for the EOI using plant specific data growth data measured from successive inspections. This procedure would provide added confidence in the predictions made using plant specific data. The analytical model also can help identify the regions of the S/G that are most susceptible to AVB wear.

A risk-based inspection program also can be developed and implemented at plants where no degradation has been detected. In this instance analytical models can be used to predict degradation distributions as a function of operating time. For example, the analytical models to predict wear degradation are described in Appendix B of [3]. Degradation distributions predicted by the analytical models can be used to determine the risk in the same manner as the distributions measured from service experience in the plant-specific data approach.

Similarly, the lead plant approach can be used to develop and implement risk-based inspection program at plants where no degradation has been detected. In this instance, the degradation distributions would be available from the lead plant. As indicated in [3], application of the lead plant approach will require demonstration of thermal hydraulic and structural similarity between S/Gs in the trailing and lead plants. In addition, the tube essential variables (e.g., denting, deposits, tube geometry changes, signal characteristics) at the lead and trailing plants should be similar.

For either the analytical model or lead plant approaches, the degradation distribution will need to be determined by inspection at the end of the predicted inspection interval and compared to the predicted distribution. If the predicted distribution does not bound the distribution determined from the inspection results, then the risk calculation will need to be updated using the distribution obtained from the inspection results.

2.2.4 Probability of Tube Failure

The probabilities of tube failure due to pressure and high temperature creep are determined for each of the degradation distributions associated with each of the specified inspection intervals.

The STEIN software [8] is used to compute the probability of S/G tube rupture for normal operating temperature and a pressure differential representing primary pressure at the relief valve set-point and a completely depressurized secondary side.

The PROBFAIL software (see Section 6.6 of [4]) is used to compute the probability that tube failure would occur prior to failure of hot leg piping due to high temperature creep rupture during the various accident sequences. PROBFAIL predicts failure based on a Larson-Miller correlation. The stress used in the Larson-Miller correlation is determined from a burst relationship simulating AVB wear degradation, as described Appendix A.

The failure probabilities determined from STEIN and PROBFAIL are used to construct Tube Rupture Event Trees (TRETs), which provide the conditional probability of both pressure and temperature induced tube failure for the various accident sequences.

The results contained in the TRETs along with the frequencies as described in Section 2.2.1 are used to determine the LERF and ΔLERF.

2.2.5 Calculation of Large Early Release Frequency

The LERF and ΔLERF are the risk measures used to determine if adequate margins exist against tube failure. LERF is the frequency of those accidents leading to significant, unmitigated releases from containment in a time frame prior to effective evacuation of the close-in population such that there are health effects [6]. The LERF is determined by linking the EOATs, APETs, and TRETs to determine the frequency that tube failure will occur and lead to a large release.

Section 7 of [4] describes the procedure to link the EOATS and APETS, and TRETs. Section 8 of [4] describes the procedure used to calculate LERF and ΔLERF.

3
RBI PROGRAM DEVELOPMENT AND IMPLEMENTATION

3.1 Overview

Implementation of the risk-based evaluation procedure to define the inspection interval includes determination of the deterministic performance inspection followed by determination of the risk-based inspection interval. The need to define a risk-based inspection interval will depend on the inspection results and the desired length of the inspection interval overall.

The procedure for developing and implementing performance based inspection (PBI) programs is illustrated in Figures 3-1 through 3-4. Figures 3-1 through 3-3 are duplicates of Figures 3-1 through 3-3 in Volume 1 of this study [3]. These three figures summarize development of the deterministic performance based inspection interval, and are included here with Figure 3-4 to illustrate the overall development and implementation process for PBI.

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 AVB 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. Figure 3-4 summarizes the procedure to define the maximum risk-based inspection interval.

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 3-4 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 if the plant started before there was time to implement a PBI program. A PBI program should include planning for in-situ testing. In-situ testing provides a means to demonstrate compliance with the performance criteria in the event the NDE measured degradation levels exceed the CML. Additionally, the potential for loose parts should be evaluated and determined to be acceptably low prior to implementing the PBI program.

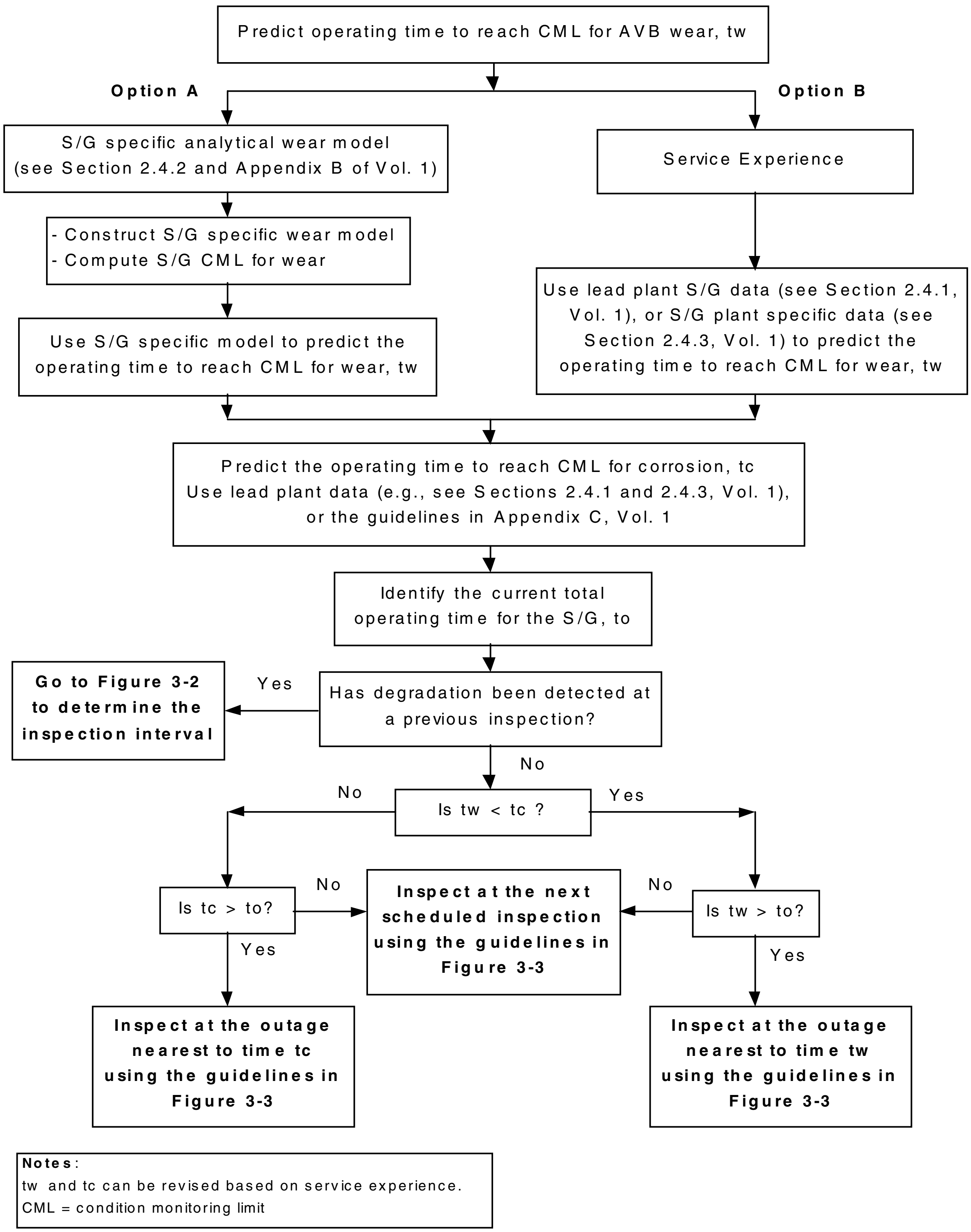
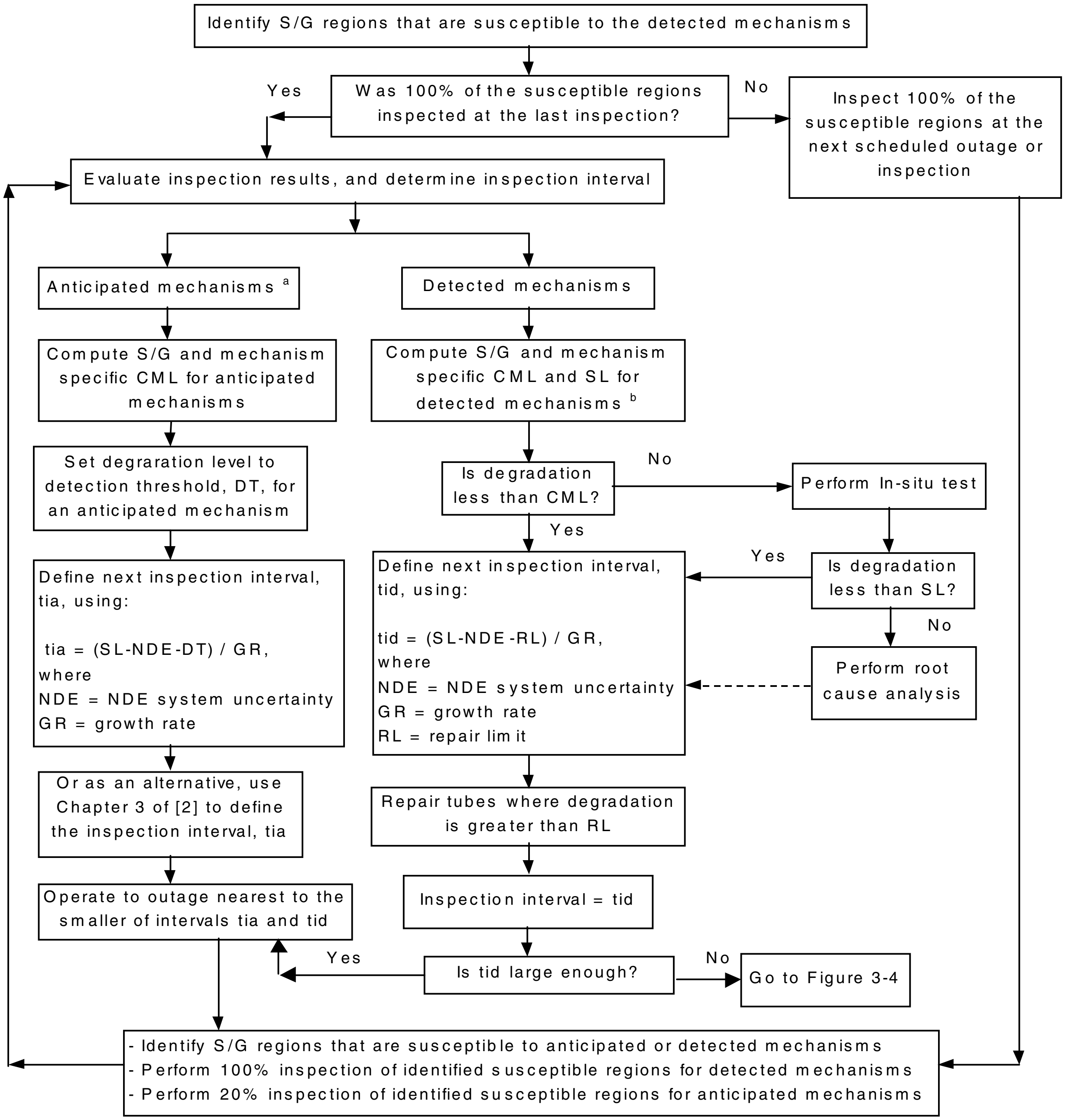


Figure 3-1
Process to Determine Inspection Interval and Sampling

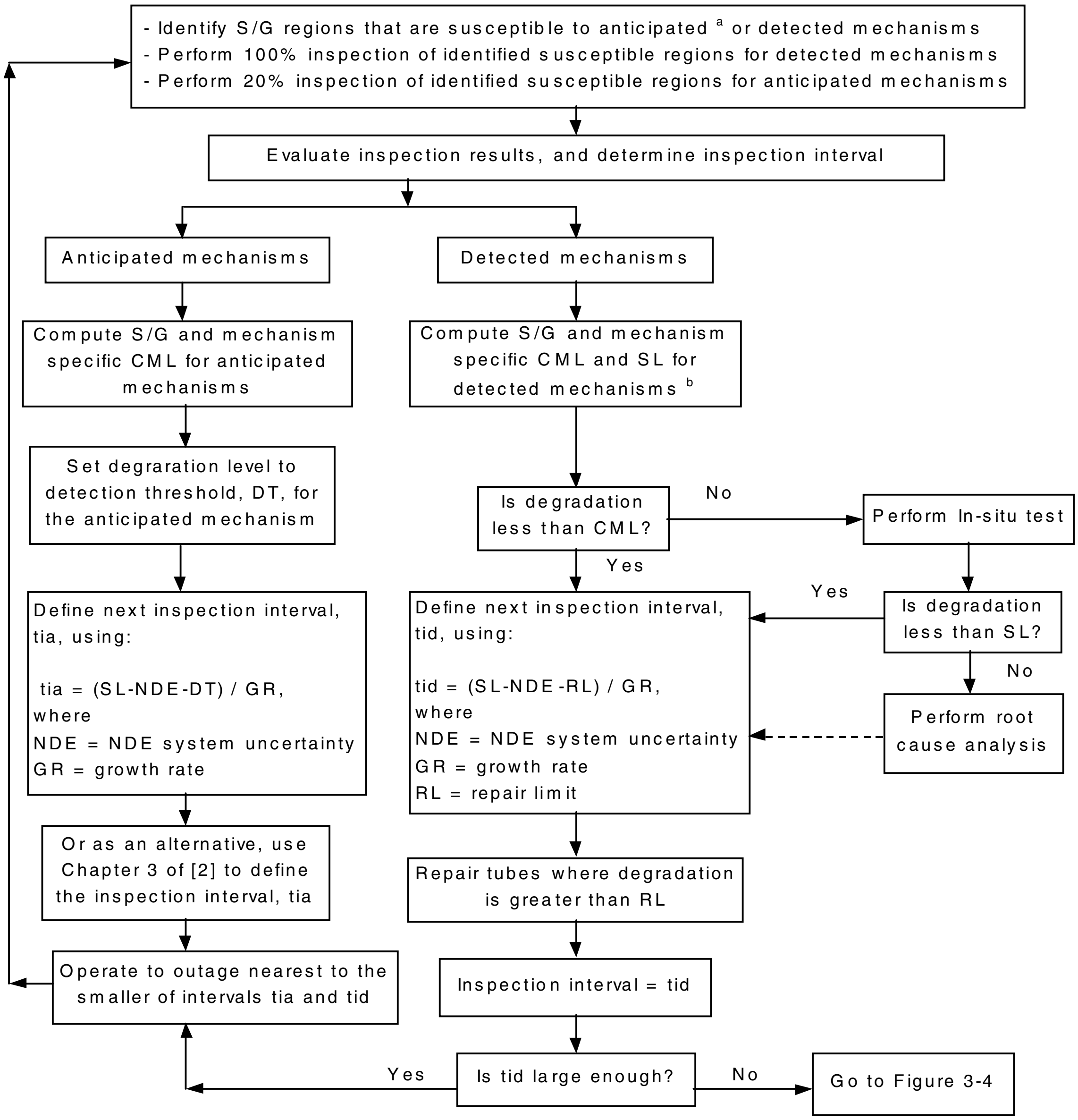


Notes:

[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 3-2
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

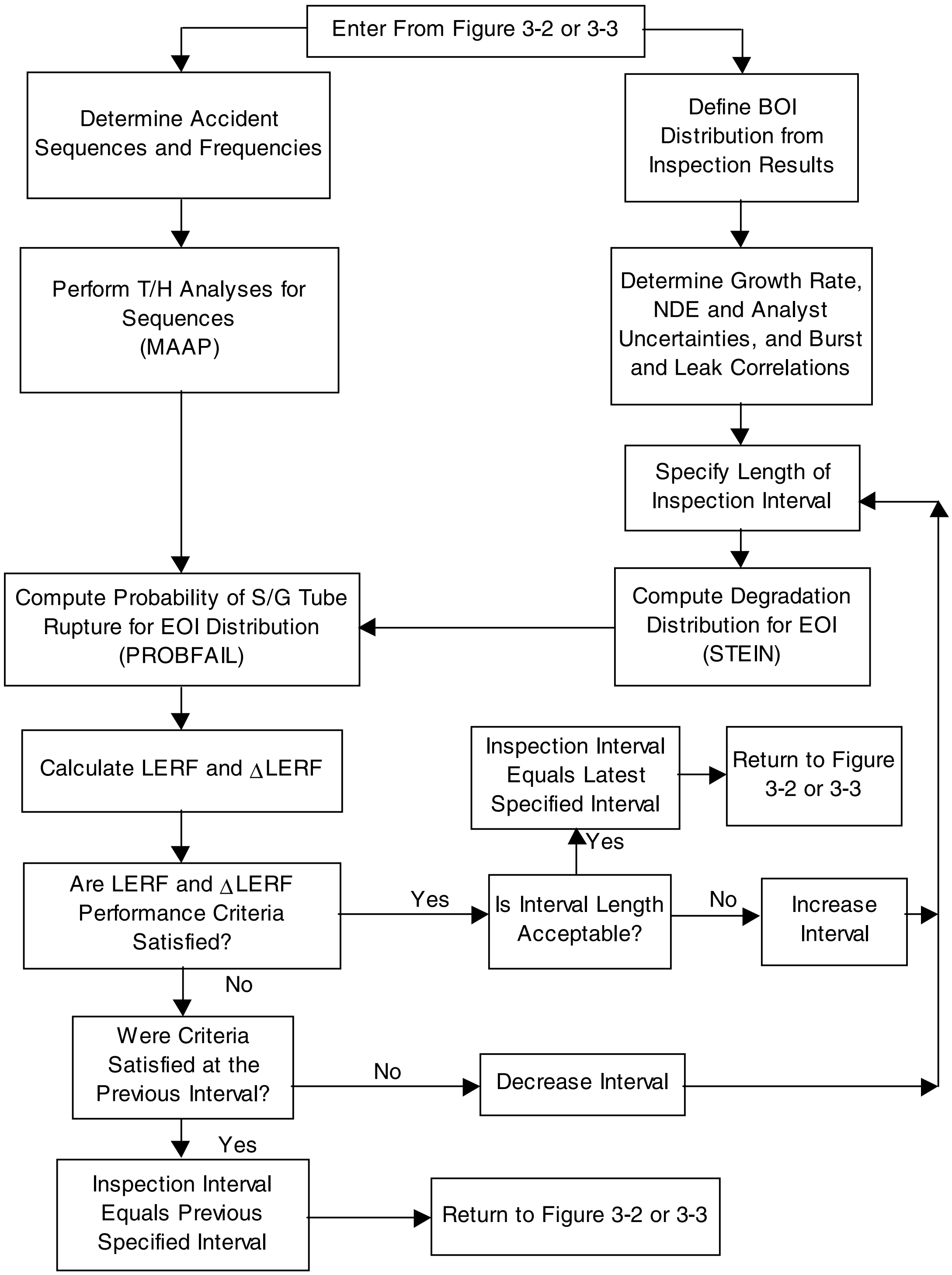


Figure 3-4
Determination of Maximum Inspection Interval Using Risk-Based Evaluation Procedures and Acceptance Criteria

3.2 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 of [3] 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 AVB wear models and plant service experience, can be used to predict the time to AVB wear degradation. Appendix B in Volume 1 [3] 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.

The second step in Figure 3-1 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 of [3] 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 of Volume 1 [3]. 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 predicted to occur first.

As an alternative, the time to corrosion degradation can be estimated using a lead plant if one is available. 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 degradation in the lead plant would reach the CML.

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. 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.

If 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 AVB wear or corrosion degradation. Figure 3-3 then is used to define the inspection scope and interval for operation beyond the shorter of the predicted time to AVB wear or corrosion degradation.

In some situations, the length of the inspection intervals defined by the deterministic performance based procedures summarized in Figures 3-2 and 3-3 may not be adequate to reach the end of an outage. In this instance, the risk-based evaluation outlined in Figure 3-4 can be used to define the maximum allowable length of the interval, and extend the inspection interval beyond that defined using the deterministic performance criteria. Application of Figure 3-4 with either Figure 3-2 or 3-3 provides additional flexibility for matching the length of the inspection interval to scheduled outages.

As an alternative to application of risk-based criteria, the prescriptive guidelines in Chapter 3 of the current revision of TR-107569 [2] can be used to define the inspection interval for anticipated degradation mechanisms. This alternative may be desirable if there are limited data (e.g., degradation growth rates, or detection threshold, DT) that can be used to assess compliance with the risk based performance criteria.

3.3 Inspection Sampling

Figures 3-1 through 3-4 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. 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 of [3]. The inspection scope includes a 20% sampling of the S/G tubes in 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.

Because the risk-based evaluation illustrated in Figure 3-4 likely will be implemented following detection of degradation, a 100% sample size of the susceptible region is required for implementing risk-based inspection programs.

The inspection scope should provide a high degree of assurance that the susceptible region has been bounded, and tubes that may be susceptible to the degradation mechanism do not have degradation levels in excess of the applicable performance criteria.

3.4 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 various performance criteria. As indicated in Figures 3-2 and 3-3, an in-situ pressure test would be required to demonstrate compliance with the applicable performance criteria 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 [9] 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.

3.5 Loose Parts Prevention

Periodic inspection programs may not be effective for monitoring degradation from random events such as loose parts. Consequently, implementation of a PBI program will require action 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. 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.

If loose parts are detected, the contribution to risk from loose parts must be determined and included in the risk evaluation.

4 CASE STUDY

This chapter presents a case study to illustrate application of the procedures described in Sections 2 and 3 for developing and implementing a performance based inspection program. This includes both deterministic and risk-based evaluation procedures and performance criteria for defining the inspection interval.

Both corrosion and AVB wear are included in the evaluation. In this case study both deterministic and risk-based evaluations were performed for AVB wear. The evaluation of corrosion degradation was performed using only deterministic evaluation procedures and criteria. Illustration of a plant-specific risk assessment for corrosion degradation has been performed previously [5], and uses the same procedures [4] as those illustrated in this report for AVB wear. Consequently, the risk evaluation scope of this case study was limited to AVB wear.

4.1 Background

A deterministic performance based inspection interval previously was determined for a 4-loop Westinghouse PWR design, as described in Section 4 of [3]. The degradation mechanisms considered in the interval determination were AVB wear and corrosion [3]. Determination of the inspection interval was based on the inspection results obtained at the end of refueling outage seven (RFO 7), after a total operating time of 8.6 EFPY. In this instance, AVB wear degradation had been detected at RFO 7 and previous outages; no corrosion degradation was detected up to RFO 7. Determination of the initial PBI interval was based on the shorter of the predicted time to corrosion degradation and the maximum operating time after RFO 7 for which the deterministic performance criteria would be satisfied for AVB wear degradation. For reference, the results from the deterministic evaluation are summarized here in Table 4-1, along with pertinent data used to generate the results.

Previously, in a separate study, event sequences and frequencies needed for the risk assessment also were determined for a 4-loop Westinghouse PWR design [5]. These previously obtained results are used in the risk analysis in this study to define the inspection interval.

This case study employs the results from the previous two studies [3,5] to illustrate the procedure used to determine the inspection interval considering both deterministic and risk based evaluation procedures and performance criteria. The illustration focuses on 2nd generation S/Gs with detected AVB wear degradation and predicted corrosion degradation sometime after RFO 7.

Section 4.2 and Appendices A and B summarize the sequences and frequencies previously determined from [5]. Additional work to determine the remaining information needed to complete the risk evaluation and define the inspection interval are described in Sections 4-3 through 4-6, and Appendices A, B and C.

Section 4.7 summarizes the results from the deterministic and risk evaluations, and defines various options for implementing the results to define inspection intervals.

Table 4-1
Summary of Data and Results For Determination of the Deterministic Performance Based Inspection Interval for a 4-Loop Westinghouse Plant [3]

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 [(a)]
NDE technique uncertainty, TU	3.82 %TW [(a)]
Condition Monitoring Limit, CML	58.3%TW
Structural Limit, SL	65.6%TW
Inspection interval based on AVB wear, tid	7.03 EFPY from time of last inspection at RFO 7
Coolant temperature at hot leg piping, T_{hot}	610 °F (321.1°C)
Time to CML for corrosion degradation, tc	17 EFPY from time S/G was placed into service, or 8.4 EFPY after RFO 7

Note (a): These NDE uncertainties were used for illustration purposes only. The standard error of regression should be determined and used to define the mechanism/location specific NDE uncertainties for plant specific evaluations.

4.2 Event Sequences and Frequencies

The work reported here builds on a previous, more comprehensive analysis [5]. Calculations were performed for six representative severe accident sequences. Sequence selection was based on the results of an extensive set of MAAP calculations and a review of the probabilistic risk assessment (PRA). The six representative sequences essentially are the same as those described in [5]; minor differences are described in Appendix A. The sequences selected result in thermal-hydraulic conditions that would be similar to those of broad classes of Level 1 PRA sequences that are expected to challenge tube integrity.

The sequences of interest for temperature induced S/G tube rupture (TISGTR) involve high reactor coolant system (RCS) pressure and dry steam generators. A brief description of the six sequences modeled follows. Additional information for the six sequences is presented in Appendix A.

1. High/dry/high (H/D/H): This sequence class represents accidents with high RCS pressure, dry steam generators, and high secondary side pressures. In this case, the cold leg loop seals (reactor coolant pump suction piping) are assumed to remain filled with water.
2. High/dry/low (H/D/L): This represents the class of accidents with intact loop seals, high RCS pressure, dry steam generators, and low secondary side pressure in one or more steam generators.
3. High/dry/low with seal LOCAs: This differs from the previous case by the presence of 180 gpm seal LOCAs in each loop. The presence of seal LOCAs increases the flow of hot gasses to the steam generators, enhancing the threat to the tubes.
4. Concurrent loop seal and core barrel clearing with both steam generators pressurized: This sequence is similar to high/dry/high, except that a cold leg loop seal is assumed to clear (empties of water) soon after core uncovering.
5. Concurrent loop seal and core barrel clearing with a steam generator depressurized in the affected loop, i.e. that with the cleared loop seal.
6. Concurrent loop seal and core barrel clearing with a steam generator depressurized in the unaffected loops containing intact loop seals.

The frequencies for the sequences were obtained from Figures 5 and 6 of Appendix B, and are listed in Table 4-2.

Table 4-2
Frequency of Sequences Identified as Potentially Initiating or Leading to Tube Rupture

Sequence	Frequency (per reactor-year)
(1) H/D/H	3E-6
(2) H/D/L	7E-6
(3) H/D/L with seal LOCAs	1E-7
(4) Same as (1), except cold leg loop seal clears	6E-8
(5) Same as (4), except S/G depressurized in loop with cleared seal	3E-9
(6) Same as (4), except S/G depressurized in loops with intact seals	8E-10

4.3 Thermal Hydraulics

Calculations were performed with the same version of MAAP as used in the previous analysis [5]. The plant model was also the same. A key phenomenon affecting the results of the analysis is radiation heat transfer in the hot legs. Since the MAAP model for this process is very simplified, the HOTLEG code was used to calculate an "effective emissivity" using a detailed radiation model. This value is input to MAAP to improve the calculated values for hot leg heat transfer rates [4]. The surge line was not evaluated for this work because previous analyses [4] indicate it does not fail before either the hot leg piping or the S/G tubes.

The methodology documented in [4] includes a step in which the MAAP hot leg temperatures are post-processed using HOTLEG to account for various perceived simplifications in the applicable MAAP models. However, more recent work has determined that the benefits of post-processing are small if HOTLEG is used to supply an effective emissivity to MAAP. For this reason, the MAAP temperatures and pressures were output to a plot file that was then read directly by PROBFAIL.

The methodology [4] outlines a series of thermal-hydraulic calculations that can be performed with the MAAP code to investigate the importance of thermal-hydraulic uncertainties affecting the likelihood of TISGTR. This was done in this study for each of the six sequences by varying certain input parameters to the phenomenological models. The most important thermal-hydraulic uncertainties are associated with the effectiveness of radiation heat transfer in the hot leg, the assumed flow pattern in the steam generators, and the degree of mixing between cold and hot gasses in the inlet plenum of the steam generator. The probability of TISGTR is evaluated separately for each case, and the overall probability for the sequence is evaluated by combining the individual results using weighting factors that reflect the degree-of-belief associated with each set of thermal-hydraulic assumptions.

4.4 Degradation Distributions

In this case study, the focus is on the S/G shown, through detailed analysis, to have AVB wear degradation that will most limit future inspection intervals for the plant. Table 4-3 provides a summary of the cumulative EFPY, number and maximum depth (in %TW) of the detected AVB wear indications, 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 4-3 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 4-3
History of AVB Wear Degradation in the Limiting S/G for a 4-Loop Westinghouse Plant

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.

The degradation distributions and associated tube rupture probabilities for various inspection intervals were determined using the operational assessment option of the STEIN [8] software. The end of RFO 7 was assumed to be the BOI. 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 4-3). Consequently, the degradation distribution at the BOI is the distribution shown in Figure 4-1 adjusted for the probability of detection (POD). The growth rate distribution used to calculate the degradation distribution for inspection intervals following RFO 7 is shown in Figure 4-2. The input needed to run the operational assessment option for the STEIN software is summarized in Table 4-4.

As indicated in Section 2.2.3.2, consideration should be given to the uncertainty associated with using degradation growth rates obtained from the previous operating cycle for predicting growth rate for extended inspection intervals. In this instance, it is judged that the are sufficient prior data to indicate predictable future growth wear degradation rates. This is based on data from seven cycles, and the trend of the data for less severe degradation and degradation rates in the last several cycles (see Table 4-3).

For this case study, the NDE uncertainties used in the STEIN software were taken to have the same numerical values as the NDE uncertainties identified in Table 4-1 and used previously for the deterministic study [3]. This was done to be able to compare the results from the deterministic study [3] with the results obtained from the risk assessment in this work.

The STEIN computational procedure computes a distribution of degraded tubes as a function of the NDE measurement parameter. The degradation distributions obtained from STEIN are shown in Figure 4-3, where the cumulative number of degraded tubes is plotted as a function of degradation level, with inspection interval (number of EFPY since the last inspection at RFO 7) as a parameter. Table 4-5 presents the probabilities of tube rupture computed by STEIN for a 2,560 psi pressure differential and normal, full power operating temperature.

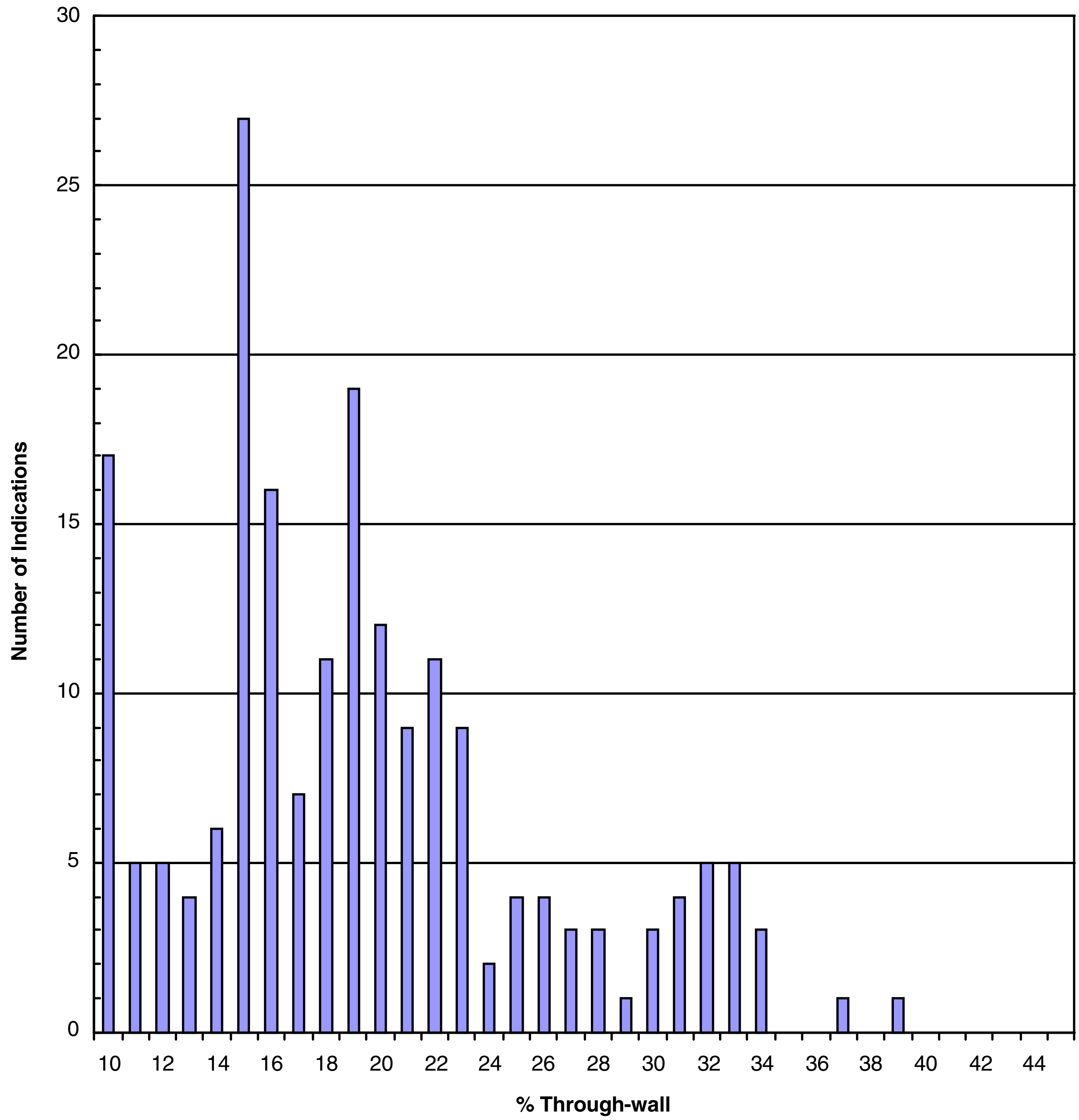


Figure 4-1
Distribution of AVB Wear Indications at Refueling Outage 7

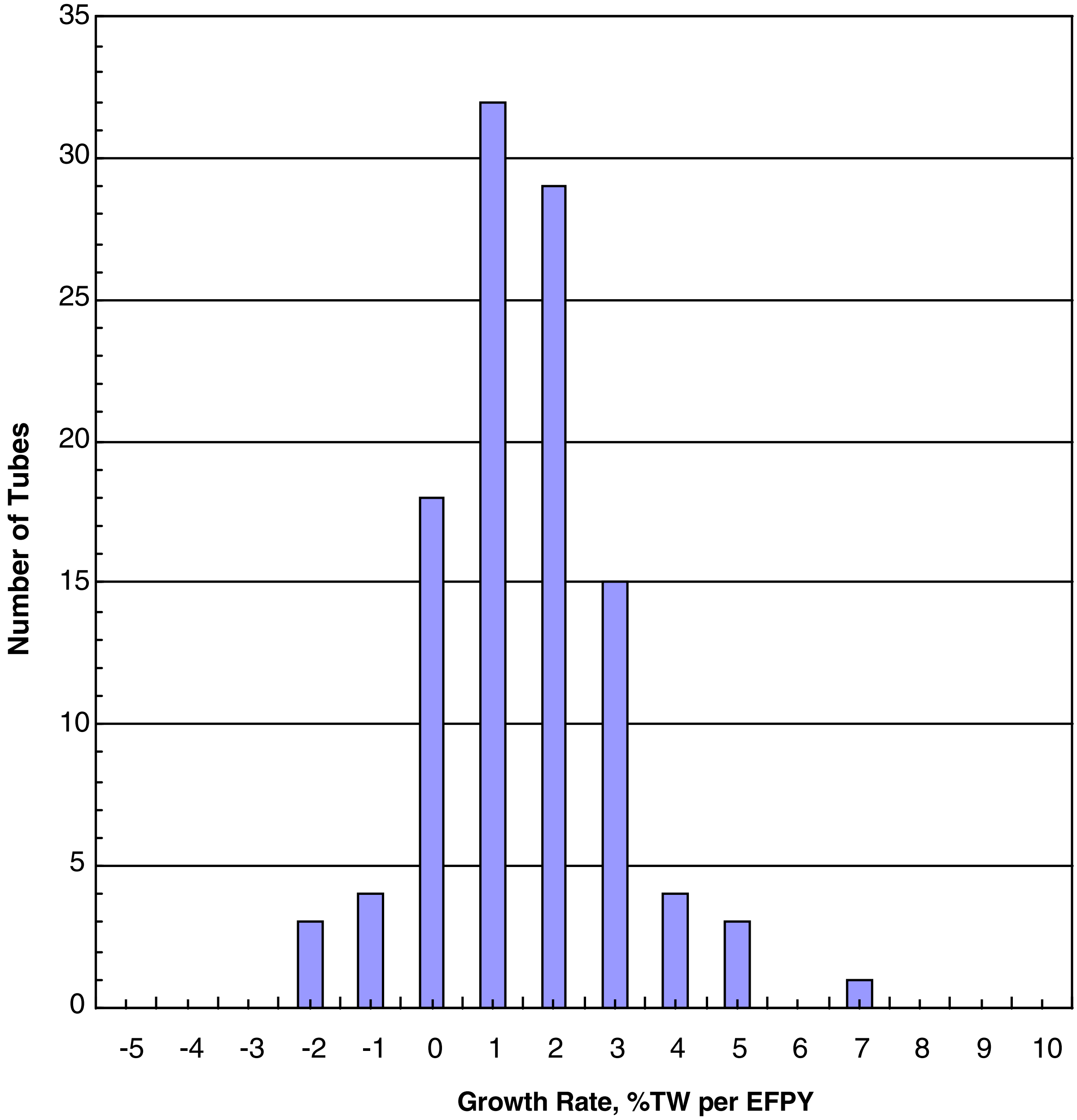


Figure 4-2
Degradation Growth Rate Distribution for AVB Wear Indications at Refueling Outage 7

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

Variable	Variable Value
Burst pressure vs NDE measurement parameter data	See Appendix C
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	See Appendix C
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 [(a)] & 0.8
Probe wear (technique uncertainty) & cut off	.0382 [(a)] & 0.8
Other uncertainty & cut off	0 & 0

Note (a): These NDE uncertainties were used for illustration purposes only. The standard error of regression should be determined and used to define the mechanism/location specific NDE uncertainties for plant specific evaluations.

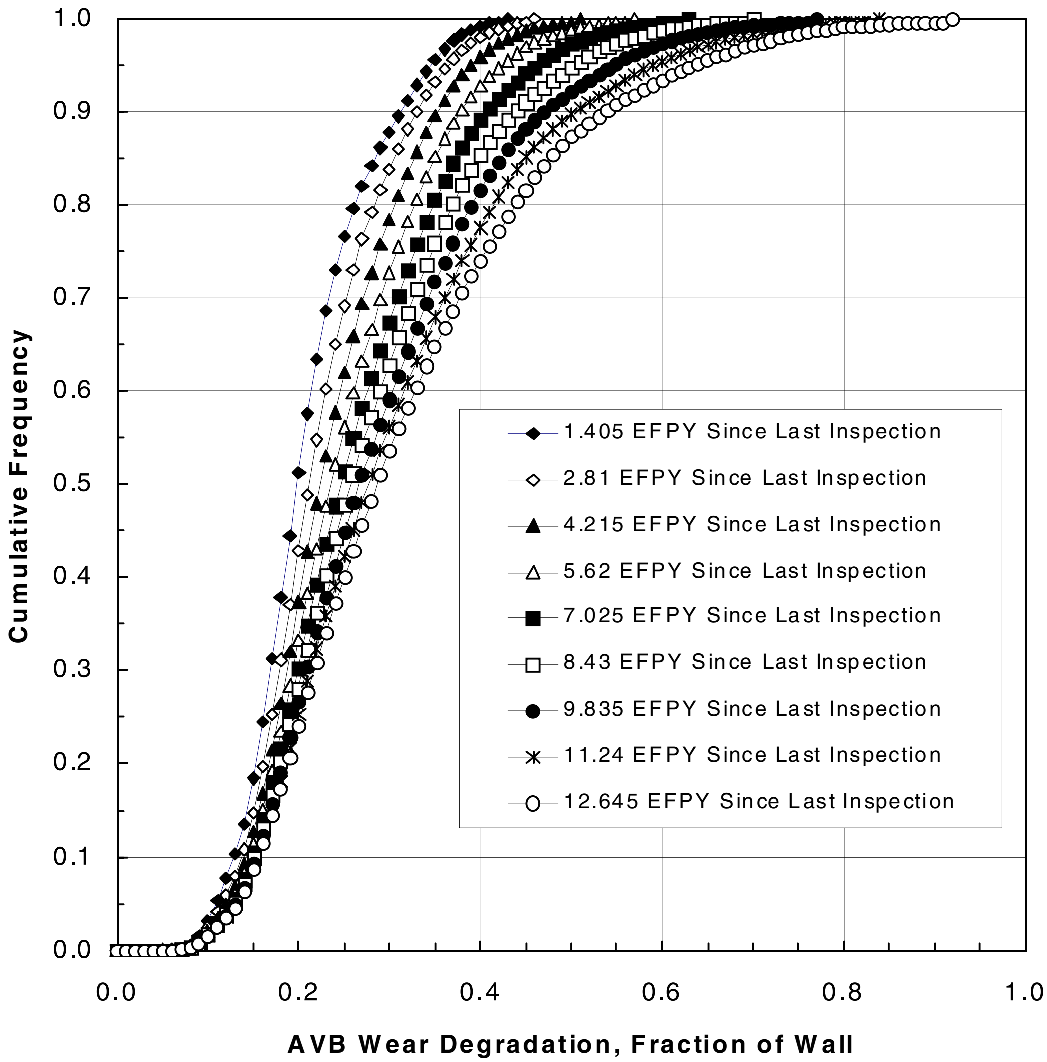


Figure 4-3
Cumulative Distribution of Indications Predicted by STEIN for Various Inspection Intervals After RFO 7

Table 4-5
Probability of Tube Rupture from STEIN Calculations: 2,560 psi Pressure Differential and Normal Full Power Operating Temperature.

RFO	EFPY After the Last Inspection at RFO 7	Cumulative EFPY	Probability of Tube Rupture
7	N/A	8.6	<1E-4
8	1.405	10.0	<1E-4
9	2.810	11.4	<1E-4
10	4.215	12.8	<1E-4
11	5.620	14.2	<1E-4
12	7.025	15.6	<1E-4
13	8.430	17.0	<1E-4
14	9.835	18.4	4.5E-3
15	11.24	19.8	4.6E-1
16	12.645	21.2	8.6E-1

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

4.5 PROBFAIL Results

The PROBFAIL code is used to compute the probability that the S/G tubes will fail prior to the failure of the hot leg piping. The PROBFAIL code used in this study was significantly upgraded compared to the version described in [4]. The principal difference that affects the work described here is a new capability to input an explicit description of defect geometry.

Distributions of calculated defect geometries as a function of operating time since the last inspection were obtained from the STEIN code as shown in Figure 4-3. The defects were characterized by a defect depth, the number of tubes in the unit having this depth (in general this is a fraction, due to the treatment of probabilities in STEIN), and the defect length. A constant 1-inch defect length was assumed for these analyses.

Creep failure of steam generator tubes at high temperature has been studied previously [10]. This work indicates that for both axial and circumferential cracks, failure of the remaining tube ligament is correlated to a quantity called m_p that is normally used to characterize ligament failure of part-through wall cracks at nominal temperatures in Design Basis Analysis. The m_p of a crack is defined by:

$$m_p = \frac{P_{burst-nom}}{P_{ligament}}$$

where $P_{burst-nom}$ is the burst pressure of a pristine tube at nominal operating temperature and $P_{ligament}$ is the pressure at which the ligament fails.

The time of creep failure of a crack ligament can be calculated by performing a standard creep rupture evaluation in which the nominal stress is multiplied by m_p to account for the deleterious effects of the crack.

No data are currently available on the high-temperature creep rupture of defects in steam generator tubes produced by AVB wear. For these analyses, it was assumed that m_p can be calculated from existing correlations for burst pressure. The relationship used to define the mean burst pressure versus flaw size relationship is: (see Section 5.5.2 of [11]):

$$P_{ligament} = 0.58(S_y + S_u)(t / R_i)[1 - (d / t)(L / (L + 2t))] + 291$$

where t is the tube wall thickness = 0.043-inch (1.1mm), d is the flaw depth, R_i is the tube inner radius = 0.332-inch (8.4mm), $S_y + S_u$ is the sum of the yield and ultimate strengths = 137,370 psi (947 MPa), and L is the flaw length = 1-inch (25.4 mm).

Additional discussion of the computational procedures and assumptions used in PROBFAIL are contained in Appendix A.

The conditional probabilities of S/G tube rupture computed by PROBFAIL for the accident sequences are presented in Table 4-6 as a function of length of the inspection interval.

Table 4-6
Conditional Probability of S/G Tube Rupture for the Risk Assessment Sequences

Sequence	EFPY After the Last Inspection at RFO 7								
	1.405	2.81	4.215	5.62	7.025	8.43	9.835	11.24	12.645
(1) H/D/H with intact loop seals	negl.*	negl.*	negl.*	negl.*	negl.*	negl.*	negl.*	negl.*	negl.*
(2) H/D/L with intact loop seals	negl.*	negl.*	negl.*	4E-6	6E-5	2E-3	.019	.069	.076
(3) H/D/L with intact loop seals and seal LOCAs	2E-5	7E-5	4E-4	2E-3	.013	.064	.18	.28	.29
(4) H/D/L with one cleared loop seal	negl.*	negl.*	negl.*	negl.*	negl.*	negl.*	4E-5	.037	.29
(5) H/D/L with one cleared loop seal in a loop with a depressurized S/G	1	1	1	1	1	1	1	1	1
(6) H/D/L with one cleared loop seal in a loop with a pressurized S/G	negl.*	negl.*	negl.*	negl.*	1E-6	2E-4	7E-3	.15	.56

*Conditional failure probability less than $1x10^{-6}$.

The results presented in Tables 4-2 and 4-6 are used to compute the S/G tube rupture frequency for each of the accident sequences as a function of the length of the operating interval. Because a tube rupture results in a large release, the large early release frequency (LERF) essentially is equal to the tube rupture frequency. The results are presented in Table 4-7.

Table 4-7
Large Early Release Frequencies (LERF) for the Risk Assessment Sequences (per reactor-year)

Sequence	EFPY After the Last Inspection at RFO 7								
	1.405	2.81	4.215	5.62	7.025	8.43	9.835	11.24	12.645
(1) H/D/H with intact loop seals	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	1E-8	1E-6	2E-6
(2) H/D/L with intact loop seals	2E-9	2E-9	2E-9	2E-9	3E-9	3E-8	4E-7	5E-6	6E-6
(3) H/D/L with intact loop seals and seal LOCAs	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	1E-9	1E-8	1E-7	1E-7
(4) H/D/L with one cleared loop seal	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	3E-8	5E-8
(5) H/D/L with one cleared loop seal in a loop with a depressurized S/G	3E-9	3E-9	3E-9	3E-9	3E-9	3E-9	3E-9	3E-9	3E-9
(6) H/D/L with one cleared loop seal in a loop with a pressurized S/G	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9

4.6 Risk Calculations

This section summarizes the results from the risk calculation. Appendix B provides additional discussion of the computational procedures and assumptions for the risk evaluation.

Because it has been previously found [4] that the principal contributions to risk are from severe accidents, this study focuses on the High/Dry sequences. The risk assessment methodology is then used to calculate changes in LERF from these sequences over a number of operating cycles, as wearing of the steam generator tubes increases.

In [5], the accident sequences were divided among three characteristic timing groups. For Early Core Damage sequences, the core is estimated to uncover around 2 hours after accident initiation, due to the unavailability of both primary and secondary cooling. Typically, the complete loss of cooling is caused by the combination of the loss of all ac power and the unavailability or failure of the turbine-driven, auxiliary feedwater (AFW) pump. These sequences are initiated by transients, such as a station blackout, that cause or lead to loss of all onsite and off site power or the loss of actuation capability for all systems that could provide primary or secondary cooling. In addition, the turbine-driven AFW pump is also unavailable. Due to the total lack of cooling, MAAP 4.0.3 typically calculates that the steam generators dry out in about 1.7 hours and the core uncovers in about 2.2 hours.

A second timing category, the Mid Core Damage sequences, is based on the failure of both ac power and inverted ac power for instrumentation and control after the battery power supply fails. The AFW system relies on dc power to support steam generator level indication and to enable the atmospheric dump valves to be opened remotely. The loss of level indication is assumed to lead to failure of the AFW function and the core is estimated to uncover at about 12 hours after accident initiation. Such sequences are characterized by a loss of both off-site and on-site ac power, typically due to a seismic event that disrupts the electrical distribution system. Thus the charging, safety injection, residual heat removal, and motor-driven AFW pumps are unavailable. The core is initially cooled through the secondary system. The turbine-driven AFW pump provides water to the steam generators, which are depressurized to about 240 psig by dumping steam through the atmospheric dump valves. At 4 hours the batteries are assumed to be depleted and steam generator level indication is lost. In the IPE and IPEEE, the AFW system is assumed to fail at this time, leading to steam generator dry out at about 10 hours and core uncovering at about 12 hours.

Finally, a third timing category, the Late Core Damage sequences, is based on sequences where ac power is available, but the AFW system is unavailable for reasons other than loss of power and the turbine-driven pumps. This category did not contribute greatly to the risk and is not considered further here.

For the Early and Mid Core Damage sequences, the risk is calculated with the aid of several event trees that describe the possible variations in operator actions (with attendant human reliability assessment), accident progression, and tube rupture potential. The possible operator actions are modeled on Expanded Operator Action Trees (EOATs), the behavior of pumps, valves, and possible variations in thermal hydraulic behavior are modeled on Accident Progression Event Trees (APETs). Failure potential of pumps and valves is discussed further in Appendix B; a more detailed treatment appears in [5]. Tube failure probabilities (both from pressure- and temperature-induced rupture) are modeled on Tube Rupture Event Trees (TRETs). Input to the TRETs comes from calculations using the STEIN [8] and PROBFAIL [4] computer codes, for pressure- and temperature-induced probabilities, respectively.

Information flows from the EOATs to the APETs, and from the APETs to the TRETs. When the trees are all linked together it is possible to compute the Large Early Release Frequency (LERF).

The EOATs and APETs were originally constructed and quantified in [5]; the EOATs were not changed for this study, but some minor changes were made to the APETs to better treat conditions where more than one steam generator is depressurized. The TRETs were originally constructed in [5], but have been enlarged for the present study. The changes to the APETs and TRETs were necessary because the STEIN calculations indicate a high probability of pressure-induced tube ruptures at later cycles, when the degree of wear at anti vibration bars (AVBs) is calculated to be high. The EOATs, APETs, and TRETs developed for this work are presented in Appendix B.

The values of ΔLERF calculated for the event sequences identified in Section 4.2 are presented in Table 4-8, as a function of the length of the inspection interval.

Table 4-8
ΔLERF for Sequences Used for Risk Assessment (per reactor-year)

Sequence	EFPY After the Last Inspection at RFO 7								
	1.405	2.81	4.215	5.62	7.025	8.43	9.835	11.24	12.645
(1) H/D/H with intact loop seals	---	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	1E-8	1E-6	2E-6
(2) H/D/L with intact loop seals	---	<1E-9	<1E-9	<1E-9	1E-9	3E-8	4E-7	5E-6	6E-6
(3) H/D/L with intact loop seals and seal LOCAs	---	<1E-9	<1E-9	<1E-9	<1E-9	1E-9	1E-8	1E-7	1E-7
(4) H/D/L with one cleared loop seal	---	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	3E-8	5E-8
(5) H/D/L with one cleared loop seal in a loop with a depressurized S/G	---	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9
(6) H/D/L with one cleared loop seal in a loop with a pressurized S/G	---	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9	<1E-9

The total values of LERF and ΔLERF calculated for the event sequences identified in Section 4.2 are presented in Table 4-9 as a function of the length of the inspection interval. Table 4-9 contains two columns for ΔLERF. The first ΔLERF column was computed using the tube condition at RFO 7 as the reference point for the calculation, while the second ΔLERF column used the tube condition at RFO 11 as the reference point for the calculation. RFO 11 is used because it is the outage closest to the time at which the condition monitoring limit (see Tables 4-1 and 4-10) is predicted to be reached. RFO 11 is taken as the reference point for the ΔLERF calculation because the risk is assessed from the time last predicted to satisfy the acceptable deterministic performance criteria for condition monitoring. For this example, the results in Table 4-9 indicate negligible differences in the values of ΔLERF calculated for the two references points for outages following RFO 11.

The results in Table 4-9 also show very small values of LERF and ΔLERF until 9.835 EFPY. Then, very rapid increases occur, due to a rapid increase in pressure-induced tube failure probability. According to the regulatory guidelines [6] (see Section 2.1), the risk level is acceptable for inspection intervals up to 8.43 EFPY after RFO 7, is marginally acceptable for 9.835 EFPY, and is unacceptable beyond approximately 10 EFPY after RFO 7.

Table 4-9
Total Values of LERF and ΔLERF for the Risk Analysis Event Sequences (per reactor year)

EFPY After the Last Inspection at RFO 7	LERF	ΔLERF from RFO 7	ΔLERF from RFO 11 (Time to CML)
1.405	6E-9	---	N/A
2.805	6E-9	<1E-9	N/A
4.215	6E-9	<1E-9	N/A
5.62	6E-9	<1E-9	0
7.025	8E-9	1E-9	<1E-9
8.43	4E-8	3E-8	3E-8
9.835	5E-7	4E-7	4E-7
11.24	7E-6	7E-6	7E-6
12.645	9E-6	9E-6	9E-6

The largest contributor to the increase in LERF from 8.43 EFPY to 9.835 EFPY is the change in the temperature-induced tube rupture probabilities, which increase by more than an order of magnitude over this period. The risk impact of this change is an increase of about 3.2E-7 per reactor-year in the frequency of temperature-induced tube rupture sequences over this period. The impact of the increase in pressure-induced tube failure probability is greatest between 9.835 and 11.24 EFPY. The pressure-induced tube rupture sequences (PISTGR) dominate LERF beyond 11.24 EFPY.

The temperature-induced tube rupture probabilities also increase after 9.835 EFPY, but not nearly as rapidly as do the pressure-induced tube rupture probabilities, because PROBFAIL removes any tubes that have been calculated to fail from pressure-induced rupture from the temperature failure calculation.

It is noted that, in all cycles, the contributions from sequences with concurrent loop seal and core barrel clearing are small. Since a significant difference of opinion still exists between the Industry and the NRC on this issue, a sensitivity study has been carried out to determine the effects of using the NUREG-1570 [12] approach to loop seal clearing. The probability of concurrent loop seal and core barrel clearing is set equal to unity when large RCP seal LOCAs occur, as was assumed in NUREG-1570.

If the NUREG-1570 assumptions are used the LERF is already 2.05E-7 per reactor-year even with no appreciable wear. This is because the PROBFAIL results indicate a tube failure probability of unity when a steam generator connected to the affected loop is depressurized (i.e., even pristine tubes would fail). As the AVB wear progresses the LERF approaches that of the Base Case. More importantly, the values of ΔLERF are close between the NUREG-1570 case and the Base Case over all of the cycles. Just as for the base case, ΔLERF does not approach Regulatory Guide 1.174 guidelines until 9.835 EFPY have elapsed.

4.7 Inspection Interval

Table 4-10 summarizes the results from the deterministic and risk-based analyses, where computational results are presented at each assumed operating time following the end of RFO 7. In addition to the results from the risk evaluation, Table 4-10 includes the %TW depth integrated back to one tube. This value is compared to the structural limit in Table 4-1 and is used to define the interval for which the deterministic performance criteria are satisfied. This is consistent with the recommendation in the EPRI S/G Tube Assessment Guidelines, (see Appendix G of [13]). The inspection interval now can be defined using the results in Table 4-10 and the procedure described in Section 3-1.

Table 4-10
Summary of Inspection Interval Calculations for AVB Wear

RFO	EFPY After the Last Inspection at RFO 7 (a)	Cumulative EFPY for the S/G	%TW Integrated Back to One Tube (b)	LERF (c)	ΔLERF from the Time to Reach the CML at RFO 11 (c)
7	N/A	8.6	N/A	N/A	N/A
8	1.405	10.0	43	6E-9	N/A
9	2.810	11.4	46	6E-9	N/A
10	4.215	12.8	51	6E-9	N/A
11	5.620	14.2	57	6E-9	0
12	7.025	15.6	63	8E-9	<1E-9
13	8.430	17.0	70	4E-8	3E-8
14	9.835	18.4	77	5E-7	4E-7
15	11.24	19.8	84	7E-6	7E-6
16	12.645	21.2	92	9E-6	9E-6

Notes: (a) EFPY projections are based on 1.405 EFPY per operating cycle.
(b) Compare with deterministic criteria, SL= 65.6% TW (see Table 4-1)
(c) Compare with criteria 2 or 3 in Section 2.1.1.

First, according to Figure 3-1 the times to AVB wear and corrosion are determined. As indicated in Table 4-1 the time to corrosion degradation previously was estimated to be 17 EFPY after the S/Gs were placed into service (or 8.4 EFPY after RFO 7). The time to corrosion degradation was determined using Figure C-1 from Appendix C of [3]. In this example, T_{hot} is equal to 610°F (321.1°C), and the predicted time to corrosion degradation is approximately 17 EFPY. As indicated in Figure C-1 in Appendix C [3], 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).

Because AVB wear degradation was detected prior to RFO 7 Figure 3-2 is used to determine the inspection scope and interval, and AVB wear is evaluated as a detected mechanism in Figure 3-2. According to Figure 3-2, if the inspection at RFO 7 included 100% of the region susceptible to AVB wear then the program can be implemented without additional inspections. Assuming 100% of the region susceptible to AVB wear was inspected at RFO 7, the parameters listed in Figure 3-2 are computed for the detected AVB wear mechanism to complete the inspection interval assessment. These parameters are listed in Table 4-1, and in particular the inspection interval determined from the deterministic performance criteria is 7.03 EFPY after RFO 7, or at RFO 12.

Up to this point the information in Table 4-10 indicates that an inspection will be required at RFO 12 because that is the last outage the deterministic criteria are satisfied for AVB wear degradation. This inspection will require 100% sample of the regions susceptible to AVB wear degradation. In addition, another inspection will be required at RFO 13 because that is the time corrosion degradation is predicted to occur. At this time corrosion will be a anticipated mechanism and a 20% sample of the regions predicted to be susceptible to corrosion degradation will need to be inspected. As indicated previously, the anticipated corrosion mechanisms are hot leg IGA/SCC at the TSP and hot leg EZ PWSCC.

Rather than perform inspections in two successive outages, the logic in Figure 3-2 provides the option to use the risk results to extend the inspection for AVB wear beyond RFO 12. In this instance, the interval determined from the deterministic performance criteria is too short, and the procedures outlined in Figure 3-4 can be used to justify extending the interval. Based on the LERF and ΔLERF results in Table 4-10 and risk-based performance criteria (3) specified in Section 2.1.1 the maximum inspection interval for AVB wear is about 8.43 EFPY, or operation to RFO 13. Based on this result the inspection interval for AVB wear can extend to RFO 13. At this outage the required inspections would include 100% of the regions susceptible to AVB wear, and 20% sample of regions susceptible to the corrosion mechanisms hot leg IGA/SCC at the TSP and hot leg EZ PWSCC.

Similarly, based on the LERF and ΔLERF results in Table 4-10 and risk-based performance criteria (2) specified in Section 2.1.1 the maximum inspection interval for AVB wear is about 9.835 EFPY, or operation to RFO 14. Based on the less stringent risk criteria (2) in Section 2.1.1 the inspection interval for AVB wear can extend to RFO 14. At RFO 14 the required inspection would include 100% of the regions susceptible to AVB wear. Although the risk evaluation could be used to justify an inspection interval of 9.835 EFPY from RFO 7 for AVB wear, an inspection for corrosion degradation would be required at RFO 13 as indicated in the previous paragraph. This inspection would include a 20% sample of regions susceptible to the corrosion mechanisms hot leg IGA/SCC at the TSP and hot leg EZ PWSCC.

Selection of the inspection interval from the above alternatives would depend on plant specific economic and safety considerations. However, an inspection for AVB wear and corrosion degradation at RFO 13 might be most cost effective because both inspections could be performed at the same outage.

When selecting the inspection interval consideration must be given to ensuring compliance with the leakage criteria in Sections 2.1.2 and 2.1.3 at the end of the interval. In this example the maximum predicted crack depths from Table 4-10 are 70% TW at RFO 13 and 77% TW RFO 14. These depths are likely to ensure that through-wall flaws will not occur during the inspection interval, and that the leakage criteria will be satisfied. If deeper cracks were predicted at the end of the interval consideration should be given to reducing the inspection interval. The interval length should be selected to preclude the presence of large flaws that may go through-wall during normal operation or postulated faulted conditions and exceed the leakage criteria in Sections 2.1.2 and 2.1.3. The guidelines in [7] provide an effective program for monitoring primary to secondary leakage. Implementing the operational actions described in the guidelines [7] ensure that the performance criteria specified in 2.1.2 and 2.1.3 are met.

4.8 In-situ Pressure Testing

It would be prudent to be prepared to perform in-situ pressure tests for any PBI program that results in inspection intervals longer than the outage at which the level of degradation exceeds the CML. The in-situ pressure test would provide a definitive indication of compliance with the performance criteria in Section 2.1 in the event the CML is exceeded. The in-situ pressure test should be performed using industry guidelines [9].

4.9 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 3.5. Consideration should be given to implementing foreign object search and retrieval on the secondary side at outages prior to tube inspection at the end of the inspection interval.

For this case study, it was assumed that no loose parts had been detected up through RFO-7. If loose parts are detected at any outage after RFO-7, the contribution to risk from loose parts must be determined and included in the risk evaluation.

5
CONCLUSIONS AND RECOMMENDATIONS

A methodology has been developed to determine inspection intervals based on meeting deterministic or risk-based 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 performance criteria would ensure that adequate safety margins are maintained and, at the same time, add flexibility to the inspection schedule, and reduce the number of inspections, inspection costs and personnel radiation exposure.

Implementation of deterministic PBI programs has the greatest benefit for 2nd generation S/Gs. Deterministic 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.

Implementation of risk-based PBI programs will benefit both 1st and 2nd generation S/Gs. Risk-based inspection programs will be effective when degradation levels are predicted to exceed the deterministic performance criteria, and there is a need to extend the inspection interval to the next refueling outage.

A complement 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 and deterministic performance criteria, showed that an inspection interval of five operating cycles could be justified for AVB wear, and would result in considerable savings in inspection costs. The case study also showed that application of risk-based performance inspection could justify extension of the inspection interval for AVB wear for one more operating cycle. This extension allowed the inspection interval for AVB wear to be coincident with the interval for corrosion degradation, and would result in additional savings in inspection costs. Application of less severe performance criteria options for AVB wear provided yet one more operating cycle for AVB wear. This would provide additional flexibility in inspection scheduling.

Regulatory guidelines [6] require consideration and analysis for risk-based regulation that is larger in scope than the methodology [4,5] used in this study. The regulatory guidelines [6] addresses issues about PRA quality, required uncertainty analysis, defense-in-depth, and blended deterministic and probabilistic analysis. These items were outside the scope of this study and were not addressed in this report. Any plant-specific use of the methodology [4,5] should be in the context of a comprehensive risk assessment, which must address these issues before being used for regulatory submittals.

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.

Accident Progression Trees (APETs)— In this report, the top events on the Accident Progression Event Trees address the failure potential of pumps and valves, and various thermal hydraulic phenomena that affect the probability of tube rupture under severe accident conditions.

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.

Condition Monitoring Limit (CML)—The condition monitoring limit is the value of the NDE measurement parameter that is compared to the values of the NDE measurement parameters from the inspection results to determine if the deterministic performance criteria are satisfied. The condition monitoring limit is equal to the structural limit minus the uncertainty in the NDE measurements.

Core Damage Frequency (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.

Detection Threshold (DT)—The flaw size that when it is present generally will just escape detection. This flaw size depends on the degradation mechanism and inspection technique. This flaw size is used to define the inspection interval for anticipated degradation mechanisms.

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

Event Tree—As used in probabilistic risk assessment, is a logic diagram that depicts the possible outcomes of key events in an accident scenario, in terms of the probability of success or failure. There are generally, but not always, two branches formed, one for the success path and one for the failure path. The values of the probabilities of success and failure are called "split fractions;" these values sum to unity at each branch. The events are typically listed sequentially (although not always chronologically) at the top of the diagram; because of this they are often called "top events." The frequency (or conditional probability) of each branch of the tree is computed by taking the products of the split fractions along the branch.

Expanded Operator Action Trees (EOATs)— Event trees that consider the various operator actions associated with maintaining secondary side integrity while attempting to avert both core damage and thermal challenge to the steam generator tubes.

Inspection Interval (maximum)—The operating time from the last inspection to the time just prior to when the maximum degradation in any tube or distribution of tubes does not exceed the degradation allowed by the 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.

Large Early Release Frequency (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.

Modular Accident Analysis Program (MAAP)— A computer program for analyzing the behavior of nuclear power plants during severe accidents. MAAP was originally developed by the Nuclear Industry in the Industry Degraded Core Rule Making (IDCOR) Program and was brought to maturity later by EPRI.

NDE Measurement Parameter—The NDE measurement parameter is the variable measured by nondestructive detection examaination (NDE) devices to detect and/or size defects. The NDE measurement parameter is degradation specific. Examples of degradation specific NDE measurement parameters include, percent through-wall degradation for wall thinning, and voltage for outside diameter stress corrosion cracking at tube support plates.

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.

PROBFAIL— PROBFAIL is software developed by EPRI for evaluating the probability that one or more steam generator tubes will fail during a severe reactor accident. The code accepts as inputs thermal-hydraulic conditions calculated by a code such as MAAP and characterizations of steam generator defects from a code such as STEIN. PROBFAIL uses these inputs to calculate the time-dependent probability of creep rupture of the various defected steam generator tubes, the surge line, and the hot legs. From these distributions, the overall probability that a tube will fail prior to another primary system component is determined.

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.

tia— The length of the performance based inspection interval determined for an anticipated degradation mechanism.

tid— The length of the performance based inspection interval determined for a detected degradation mechanism.

Time to Corrosion Degradation (tc)— The predicted time to reach the CML for corrosion degradation.

Time to Wear Degradation (tw)— The predicted time to reach the CML for AVB wear degradation.

Total Operating Time (to)—The total operating time for the steam generator at the time when a PBI program is implemented. This time is compared to tc and tw at the beginning of a PBI program to determine the times to the initial inspection for degradation mechanisms that have not been detected previously.

Tube Rupture Event Trees (TRETs)— These event trees are logic diagrams with top events for the probabilities of pressure-induced and temperature-induced tube failures for the various accident sequences. The sum of the frequencies of the failure branches equals the Large Early Release Frequency (LERF).

7
LIST OF ACRONYMS

AFW	Auxiliary feedwater
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
HRA	Human reliability assessment
IGA	Intergranular attack
IPE	Individual plant examination
IPEEE	Individual plant examination of external events
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
PISGTR	Pressure induced steam generator tube rupture
POD	Probability of detection
PRA	Probabilistic risk assessment
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
TISGTR	Temperature induced steam generator tube rupture
T/S	Technical specifications

TSP	Tube support plate
TT	Thermally treated
TU	NDE technique uncertainty
TW	Through-wall
US	United States

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A
THERMALLY-INDUCED S/G TUBE RUPTURE FOR AVB WEAR

A.1 Method

The probability of thermally-induced steam generator tube rupture (TISGTR) in steam generators experiencing wear at the AVBs was calculated for postulated severe accident conditions. The calculations relied on a methodology developed previously [4]. A summary of the analysis is provided below.

Overview

The analysis consists of three principal steps. First, the defects caused by AVB wear that are expected to be present in the steam generator tubes are characterized using the STEIN code at different times in the unit's life. Next, thermal-hydraulic calculations of tube temperatures are calculated for the accident sequences of interest using MAAP. Finally, the defect data and the temperature/pressure results from the MAAP calculations are input to the PROBFAIL code. PROBFAIL calculates the probability that a steam generator tube will fail prior to some other component in the reactor coolant system (RCS) by modeling the structural response of the various components during the accident.

Sequence Selection

The work reported here builds on a previous, more comprehensive analysis of Diablo Canyon [5]. Calculations were performed for 6 representative severe accident sequences. Sequence selection was based on the results of an extensive set of MAAP calculations and a review of the Diablo Canyon Probabilistic Risk Assessment (PRA). The 6 representative sequences are essentially the same as those described in Appendix B of [5] ; minor differences are noted below. The sequences selected result in thermal-hydraulic conditions that would be similar to those of broad classes of Level 1 PRA sequences that are expected to challenge tube integrity.

The sequences of interest for TISGTR involve high reactor coolant system (RCS) pressure and dry steam generators. A brief description of the six sequences modeled follows.

High/dry/high: This sequence class represents accidents with high RCS pressure, dry steam generators, and high secondary side pressures. In this case, the cold leg loop seals (reactor coolant pump suction piping) are assumed to remain filled with water. For this reason, a counter-current flow of high temperature gas develops in the hot legs, heating the hot leg piping, surge line, and steam generator tubes. The sequence was modeled by a short-term station blackout (SBO) accident with cycling main steam safety valves (MSSVs).

High/dry/low: This represents the class of accidents with intact loop seals, high RCS pressure, dry steam generators, and low secondary side pressure in one or more steam generators. It was modeled by an SBO accident with one fully stuck-open MSSV.

High/dry/low with seal LOCAs: This differs from the previous case by the presence of 180 gpm seal LOCAs in each loop. The presence of seal LOCAs increases the flow of hot gasses to the steam generators, enhancing the threat to the tubes.

Concurrent cold leg and core barrel loop seal clearing with both steam generators pressurized: This sequence is similar to high/dry/high, except that a cold leg loop seal is assumed to clear (empty of water) soon after core uncovering. Loop seal clearing is assumed to result from the differential pressure that develops across the cold leg because of the presence of 180 gpm seal LOCAs in each loop. The differential pressure is eliminated when one loop seal clears, so the other loop seals are assumed to remain intact. For conservatism, this event is assumed to be immediately followed by clearing of the core barrel loop seal. If two loop seals become cleared in this fashion, unidirectional rather than counter-current flow of hot gasses will develop in the affected loop. This in turn leads to relatively uniform temperatures in that loop and a more severe challenge of the tube than would occur with intact loop seals and counter-current flow. In reality, clearing of the core barrel loop seal would occur later in the sequence, perhaps after hot leg or surge line rupture, so these assumptions should be considered rather pessimistic.

Concurrent cold leg and core barrel loop seal clearing with a steam generator depressurized in the affected loop, i.e. that with the cleared loop seal.

Concurrent cold leg and core barrel loop seal clearing with a steam generator depressurized in the unaffected loops containing intact loop seals.

As in previous analyses, surge line failure was conservatively neglected in these calculations. With current MAAP modeling, surge line failure is unlikely unless a pressurizer relief or safety valve remains open.

Consideration of Thermal-Hydraulic Uncertainties

The EPRI methodology outlines a series of thermal-hydraulic calculations that can be performed with the MAAP code to investigate the importance of thermal-hydraulic uncertainties affecting the likelihood of TISGTR. This was done in this study for each of the 6 sequences by varying certain input parameters to the phenomenological models. The most important thermal-hydraulic uncertainties are associated with the effectiveness of radiation heat transfer in the hot leg, the assumed flow pattern in the steam generators, and the degree of mixing between cold and hot gasses in the inlet plenum of the steam generator. The probability of TISGTR is evaluated separately for each case, and the overall probability for the sequence is evaluated by combining the individual results using weighting factors that reflect the degree-of-belief associated with each set of thermal-hydraulic assumptions.

MAAP Calculations

Calculations were performed with version 4.0.3 of MAAP as used in the previous Diablo Canyon analysis [5]. The plant model was also the same (see section 6.3.2 of [4]). As mentioned above, a key phenomenon affecting the results of the analysis is radiation heat transfer in the hot legs. Since the MAAP model for this process is very simplified, the HOTLEG code was used to calculate an "effective emissivity" using a detailed radiation model. This value is input to MAAP to improve the calculated values for hot leg heat transfer rates as discussed in section 6.4.1 of [4].

The methodology documented in section 6.5 of [4] includes a step in which the MAAP hot leg temperatures are post-processed using HOTLEG to account for various perceived simplifications in the applicable MAAP models. However, more recent work has determined that the benefits of post-processing are small if HOTLEG is used to supply an effective emissivity to MAAP. For this reason, the MAAP temperatures and pressures were output to a plot file that was then read directly by PROBFAIL.

PROBFAIL Calculations and Defect Characterization

The PROBFAIL code used in the new analysis was significantly upgraded compared to the version described in section 5 of [4]. The principal difference that affects the work described here is a new capability to input an explicit description of defect geometry.

A distribution of calculated defect geometries was obtained from the STEIN code at various points in the life of the unit. For these calculations, the defects were characterized by a defect depth, the number of tubes in the unit having this depth (in general this is a fraction, due to the treatment of probabilities in STEIN), and the defect length. A constant 1 inch defect length was assumed for these analyses. An example of the first portion of the PROBFAIL defect file is provided in Table A-1. As shown, the file was created simply by adding a header to the beginning of the STEIN output file. The header defines the format of the file and provides other required information to PROBFAIL.

A key example of the information provided in the header of the defect file is the specification of the probability that a given tube defect experiences the high temperatures characteristic of out-flow from the steam generator inlet plenum to the outlet plenum. This applies to all accident sequences involving counter-current flow (no loop seal clearing); when loop seal clearing occurs, all the tubes experience essentially the same temperature, so these considerations become moot. Based on the organization of the MAAP model, the tubes in the steam generator are divided into three groups:

(1) those tubes that experience the peak temperatures present at the center of the hot plume of gas rising from the hot leg to the tubesheet

(2) the tubes that see the cooler, average conditions present in the plume

(3) the tubes that experience the cold gas returning from the outlet plenum of the steam generator to the inlet plenum.

As can be seen in the header portion of Table A-1, the probabilities that a given defect is present in each of these three groups are considered to be 10, 40, and 50 percent, respectively. Thus, any defect has a 50 percent chance of essentially not being challenged by high temperatures at all.

Creep failure of steam generator tubes at high temperatures has been studied by researchers at Argonne National Laboratory (ANL) [10]. They found that for both axial and circumferential cracks, failure of the remaining tube ligament is correlated to a quantity called m_p that is normally used to characterize ligament failure of part-through wall cracks at nominal temperatures in Design Basis Analysis. The m_p of a crack is defined by:

$$m_p = \frac{P_{burst-nom}}{P_{ligament}}$$

where $P_{burst\text{-}nom}$ is the burst pressure of a pristine tube at nominal operating temperature and $P_{ligament}$ is the pressure at which the ligament fails. In the case of cracks that are pressurized to failure at nominal temperatures, ligament failure does not necessarily lead to burst: short cracks will undergo ligament failure and begin to leak at lower pressures than is required for unstable crack propagation (i.e. burst). Unstable crack propagation is characterized by a related quantity called m, defined by:

$$m = \frac{P_{burst-nom}}{P_{burst}}$$

where P_{burst} is the burst pressure. Leak before break, such as occurs for relatively short cracks, implies that m is smaller than m_p. Various correlations for m_p and m have been developed for axial and circumferential cracks.

ANL also determined that analogous behavior is seen in the creep failure of tubes containing cracks at high temperatures. The time of creep failure of a crack ligament can be calculated by performing a standard creep rupture evaluation in which the nominal stress is multiplied by m_p to account for the deleterious effects of the crack. However, creep failure of a ligament does not necessarily lead to burst, just as in the case at low pressures. In fact, ANL determined that the criterion $m<m_p$, which defines the occurrence of leak before break at low temperatures, is a conservative representation of this effect at high temperatures. In other words, some cracks with m larger than m_p will leak before they rupture.

No data is currently available on the high-temperature creep rupture of defects in steam generator tubes produced by AVB wear. Moreover, while the burst pressure of worn tubes has been correlated to the length and depth of the worn region, the pressure at which such regions would begin to leak is not known, if leakage occurs prior to burst. For these analyses, it was assumed that the role of m_p in the creep analysis would be played by m, which can be calculated from existing correlations for burst pressure. Based on previous work with cracked steam generator tubes, this is believed to be conservative. To see this, consider that there are two possible conditions:

m greater than m_p. In this case, the burst pressure and the ligament failure pressure are equal. Thus a burst correlation for worn tubes supplies the appropriate stress multiplication factor m_p for use in the creep rupture analysis.

m less than m_p. In this case, a worn tube will have ligament failure and begin to leak at a pressure lower than its burst pressure. The burst correlation will yield m, not m_p. Use of m values derived from the burst correlation would appear to lead to nonconservative results, i.e. use of a too small stress multiplication factor. However, previous experience with cracks indicates that the calculated TISGTR probability resulting from such a procedure will be conservative, since the leak-before-break tendency is even more pronounced at high temperatures than at low. In other words, while using m in the creep rupture analysis will predict a time of ligament failure that is later than would be observed, the calculated time will still be earlier than the actual time of burst.

A.2 Results

The TISGTR probabilities from the STEIN/MAAP/PROBFAIL analysis are summarized below for 10 different times following steam generator repair: 1.405, 2.81, 4.215, 5.62, 7.025, 8.43, 9.835, 11.24, 12.645, and 14.05 effective full power years (EFPY). The results for the high/dry/low sequences, which often dominate the risk posed by induced steam generator tube rupture, will be discussed to illustrate details of the analysis. The remainder of the results will then be summarized.

High/Dry/Low Sequence

Table A-2 shows the results obtained for the depressurized steam generator in the high/dry/low sequence at 9.835 EFPY. A more complete description of the various phenomenological cases listed in Table A-2 is provided in section 6.3.4 of [4], along with the scheme used to assign a relative likelihood to each case. As in previous TISGTR analyses, the conditional failure probability of the depressurized steam generator is larger or smaller than that calculated for the base case depending on whether more or less adverse assumptions are made. For example, increasing the radiation heat transfer from the hot leg gasses to the wall causes the hot leg piping to heat faster and to fail sooner in the accident. All else being equal, this reduces the probability that a defected tube will fail prior to the hot leg.

The calculated TISGTR probability in a fully pressurized steam generator is negligible for this sequence. This is primarily because the stress applied to the tubes is less than the situation where the steam generator is depressurized.

The aggregated results for this sequence are obtained by summing over all the uncertainty cases using the relative likelihood as weighting factors. Table A-2 illustrates that the aggregated result is fairly close to that obtained with best-estimate assumptions. This is a typical result, due to the fact that the cases with results worse than the best-estimate are compensated for by those with better results. The effect of time on the aggregated results is shown in Table A-3 and Figure A-1. “Negligible” in Table A-3 and subsequent tables means that the calculated failure probability is less than $1x10^{-6}$; such small values cannot significantly contribute to LERF.

As shown in Figure 1, the increase in failure probability with time is somewhat slowed at times greater than 9.835 EFPY. This occurs because of the increase in the probability that the most severe defects fail due to pressure prior to core uncovering: PROBFAIL does not credit thermally-induced failures of defects that, if actually present in the unit, would have already failed due to differential pressure prior to core uncovering. Of course, any beneficial effect is more than offset by the increase in pressure-induced steam generator tube rupture, which is treated separately.

High/Dry/Low Sequence with Seal LOCAs

MAAP models 2 loops, denoted "B" and "U". This somewhat misleading terminology was originally intended to label the "broken" and "unbroken" loops, but in the current versions of the code either loop can contain breaks and either can be connected to the surge line. The B loop represents a single loop of the actual plant and the U loop represents the remainder (in this case 3 loops). During the course of this analysis, it was discovered that a slightly more complete analysis of high/dry/low sequences was necessary when reactor coolant pump seal LOCAs are present than was used in previous studies. The reasons for this are described below.

As mentioned previously, the code contains no explicit model for loop seal clearing. When one or more seal LOCAs are present in the isolated volume of the cold leg lying between the filled loop seals, the code by default directs the hot gasses needed to supply the breaks through the MAAP "U" loop. Thus, the hot gasses are spread amongst several steam generators. On physical grounds, it is reasonable and conservative to expect that one of the loop seals will be depressed more than the others, and for this reason it will supply most of the gas flowing out through the failed coolant pump seals. This in turn will direct most of the hot gas to flow through only one of the steam generators, causing its tubes to become hotter than those in the other loops.

Such a situation is easily modeled in MAAP by placing a single break in a location just upstream of the MAAP B-loop loop seal. The flow area of this break should be the sum of all the failed seals' individual flow areas. This causes all the break flow to pass through the B-loop steam generator. When this is done, the results for high/dry/low sequences will depend on whether the B-loop steam generator is depressurized or not. Because of limitations in the MAAP counter-current flow models, it should be noted that the results will be conservative: the flow induced by the seal LOCAs does not mix in the inlet plenum (as it should) with cold gasses circulating back from the outlet plenum.

To determine TISGTR probabilities for high/dry/low sequences with seal LOCAs, three sets of calculations were performed with MAAP and PROBFAIL. In all of these calculations, the break flow was directed to the cold leg loop seal in the B loop.

Case 1: The B steam generator is depressurized. In this case, the conditional failure probability of the B steam generator provides information on the likelihood of TISGTR for the case where the depressed loop seal and a depressurized steam generator are in the same loop. This tends to be a relatively severe situation, since an increased flow of hot gas is supplied to a steam generator experiencing the maximum possible differential pressure.

Case 2: The U steam generators are depressurized. In this case, the conditional failure probability of one of the U steam generators provides information on the likelihood of TISGTR when the depressed loop seal and a depressurized steam generator are in different loops.

Case 3: All the steam generators are depressurized.

The PROBFAIL results for these three cases were combined using Boolean arithmetic in a spreadsheet to provide the TISGTR probabilities for any situation of interest. In performing these calculations, it is implicitly assumed that a single loop seal carries the break flow and that the probability that any given loop does this is equal and independent of conditions on the secondary side of the associated steam generator. The aggregated results are shown in Table A-4. Again, it should be noted that the thermally-induced failure probabilities are reduced as the pressure-induced failure probability increases at times greater than 9.835 EFPY and that these results are conservative because of the previously mentioned limitations of the MAAP inlet plenum mixing model

Results from Other Sequences

Table A-5 provides the aggregated results for all but one of the other sequences. Not shown are the results for the case in which the loop seal becomes cleared and the affected loop is depressurized. The failure probability is unity at all times for this sequence. The high TISGTR probability is qualitatively related to the phenomenon discussed in the previous section: loop seal clearing causes a very high flow rate of hot gas to pass through the steam generator in the affected loop. In this case, the “conservatism” mentioned above is realistic, since there is no mixing between hot and cold gasses in the inlet plenum of the steam generator. If this steam generator is depressurized, the failure probability can be expected to be quite large. While this case is quite severe and in fact can challenge even pristine tubes, the risk still tends to be dominated by the high/dry/low sequences described previously because of their higher likelihood of occurrence.

In the last column of Table A-5, there is a noteworthy case in which the TISGTR probability actually drops slightly between 11.24 EFPY and 12.645 EFPY. This is another situation in which the most severe defects present in the steam generator at 12.645 EFPY would have failed due to pressure prior to core uncovering. This reduces the TISGTR probability but the overall induced rupture probability increases.

Table A-1
Example of the Beginning Portion of a PROBFAIL Input File

```
c ********************************************

c * PROBFAIL input file for AVB wear at 9.835 EFPY*

c ********************************************

discrete defect representation
temperature probability distribution (cold, avg, hot): 0.5 0.4 0.1
nominal tube burst pressure 9990 psid
scaling factor for probabilities 1.
no leak before break modeled
c
c template to read this file:
c
fractional depth column 1
length constant 1. inch
orientation constant w
conditional probability column 2
c
0,0.000
0.01,0.000
0.02,0.000
0.03,0.000
0.04,0.000
0.05,0.013
0.06,0.022
0.07,0.072
0.08,0.427
0.09,1.252
0.1,1.714
0.11,2.206
0.12,2.234
0.13,2.746
```

Table A-2
Calculated Probability of TISGTR in Depressurized Steam Generator for High/Dry/Low Sequence at 9.835 EFPY

Phenomenological Case	Relative Likelihood	TISGTR probability for depressurized steam generator
Best-Estimate	0.408	0.016
High inlet plenum mixing	0.117	0.0045
Low inlet plenum mixing	0.058	0.032
High hot leg thermal radiation	0.136	0.008
Low hot leg thermal radiation	0.136	0.039
Low steam generator recirculatory flow	0.102	0.029
Best combination of factors	0.039	0.0035
Worst combination of factors	0.005	0.13
Aggregated results	1.0	0.019

Table A-3
Effect of Time on the Calculated Probability of TISGTR in the Depressurized Steam Generator for the High/Dry/Low Sequence

Time (EFPY)	Conditional Failure Probability for Depressurized Steam Generator in High/Dry/Low Sequence
1.405	negligible
2.81	negligible
4.215	negligible
5.62	4.3×10^{-6}
7.025	6.3×10^{-5}
8.43	1.7×10^{-3}
9.835	0.019
11.24	0.069
12.645	0.076
14.05	0.122

Table A-4
TISGTR Probability for Seal LOCA Cases, as a Function of Time and the Number of Steam Generators Depressurized

Time (EFPY)	1 SG depressurized	2 SGs depressurized	4 SGs depressurized
1.405	2.0×10^{-5}	4.1×10^{-5}	5.7×10^{-7}
2.805	6.5×10^{-5}	1.3×10^{-4}	1.7×10^{-6}
4.215	3.8×10^{-4}	7.5×10^{-4}	1.2×10^{-5}
5.62	2.4×10^{-3}	4.9×10^{-3}	1.2×10^{-4}
7.025	0.013	0.026	1.2×10^{-3}
8.43	0.064	0.13	0.021
9.835	0.18	0.36	0.18
11.24	0.28	0.52	0.48
12.645	0.29	0.54	0.51
14.05	0.33	0.6	0.68

Table A-5
Conditional Probability of TISGTR for Various Sequences Other than High/Dry/Low

Time (EFPY)	high/dry/high	loop seal clearing, affected loop SG, pressurized[1]	loop seal clearing, unaffected loop SG, pressurized[1]	loop seal clearing, affected loop SG, pressurized[2]	loop seal clearing, unaffected loop SG, depress.[2]
1.405	negligible	negligible	negligible	negligible	negligible
2.81	negligible	negligible	negligible	negligible	negligible
4.215	negligible	negligible	negligible	negligible	negligible
5.62	negligible	negligible	negligible	negligible	negligible
7.025	negligible	negligible	negligible	negligible	1×10^{-6}
8.43	negligible	negligible	negligible	8.6×10^{-6}	1.4×10^{-4}
9.835	negligible	3.7×10^{-5}	negligible	1.7×10^{-3}	5.4×10^{-3}
11.24	negligible	0.037	negligible	0.12	0.037
12.645	negligible	0.29	negligible	0.54	0.032
14.05	negligible	0.33	negligible	0.59	0.053

[1]Affected and unaffected loops pressurized
[2]Affected loop steam generator pressurized, unaffected loop units are depressurized

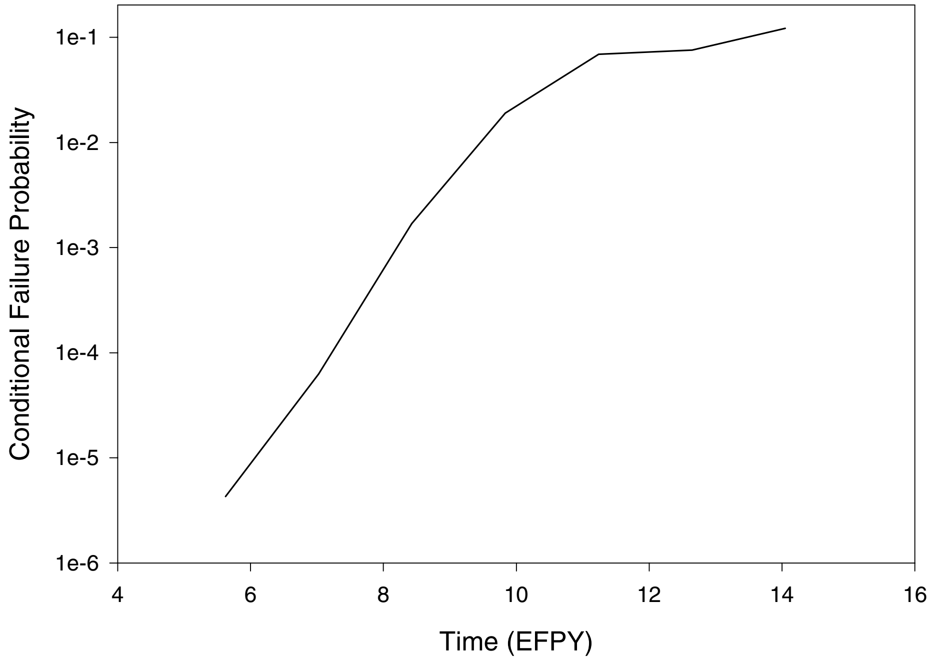

Figure A-1
Effect of Time on TISGTR Probability in High/Dry/Low Sequence

B
RISK EVALUATION FOR AVB WEAR

The risk from failure of worn steam generator tubes during postulated severe accident conditions has been calculated, using a method developed previously by EPRI [B-1,B-2]. The analysis was carried out on Plant A, a four-loop Westinghouse plant analyzed in the previous EPRI studies. A summary of the analysis is provided below.

B.1 Evaluation of Risk Impacts from Changes to Current Licensing Basis

The NRC has recently issued draft documents intended to support proposed regulations on steam generator tube integrity. In particular, a Probabilistic Risk Assessment (PRA) is described in NUREG-1570 [B-3] for evaluating the risks from operating with degraded steam generator (SG) tubes, and an approach for using PRA to make risk-informed decisions on changes to a plant's current licensing basis (CLB) is provided in Regulatory Guide 1.174 [B-4]. It is the NRC's intention that the utilities carry out risk assessments in order to support requests to use Alternate Repair Criteria (ARC) for continued use of degraded steam generator tubes. In Regulatory Guide 1.174 it is stated that licensees submitting risk information should address each of the principles of risk-informed regulation, and identify how chosen approaches and methods are appropriate for the decision to be made.

The risk-based performance criteria for LERF are based on the guidelines in [B-4] and are used to evaluate applications for changes in a plant's licensing basis. The performance criteria are explained as follows in Reference [B-4]:

> "If the application clearly can be shown to result in a decrease in LERF, the change will be considered to have satisfied the relevant principle of risk-informed regulation with respect to LERF.
>
> When the calculated increase in LERF is very small, which is taken as being less than 10^{-7} per reactor year, the change will be considered regardless of whether there is a calculation of the total LERF. While there is no requirement to calculate the total LERF, if there is an indication that the LERF may be considerably higher than 10^{-5} per reactor year, the focus should be on finding ways to decrease rather than increase it. Such an indication would result, for example, if (1) the contribution to LERF calculated from a limited scope analysis, such as the IPE or the IPEEE, significantly exceeds 10^{-5}, (2) a potential vulnerability has been identified from a margins-type analysis, or (3) historical experience at the plant in question has indicated a potential safety concern.
>
> When the calculated increase in LERF is in the range of 10^{-7} per reactor year to 10^{-6} per reactor year, applications will be considered only if it can be reasonably shown that the

total LERF is less than 10^{-5} per reactor year.

Applications that result in increases to LERF above 10^{-6} per reactor year would not normally be considered."

The risk-based criteria used to ensure adequate tube integrity are consistent with [B-4], and are:

1. A distribution of degraded S/G tubes has an unacceptable margin against tube rupture for accident conditions when ΔLERF is greater than 1E-6 per reactor-year.

2. A distribution of degraded S/G tubes has a marginally acceptable margin against tube rupture for accident conditions when LERF is less than 1E-5 per reactor-year and ΔLERF is between 1E-6 and 1E-7 per reactor-year.

3. A distribution of degraded S/G tubes has an acceptable margin against tube rupture for accident conditions when LERF is less than 1E-5 per reactor-year and ΔLERF is less than 1E-7 per reactor-year.

In addition, DG-1074 [B-5] states repeatedly that proposed changes pertaining to probabilistic structural and accident leakage performance criteria should be supported by a risk assessment with appropriate consideration of defense-in-depth (i.e., the containment function of steam generator tubes). Guidance for submitting proposed changes to the licensing basis is provided in Regulatory Guide 1.174 [B-4].

Risk impacts are measured in terms of changes in core damage frequency (CDF) and large early release frequency (LERF), and are dominated by contributions from severe accidents [B-1,B-3]. Large early release frequency (LERF) is "the frequency of those accidents leading to significant, unmitigated releases from containment in a time frame prior to effective evacuation of the close-in population such that there is a potential for early health effects" [B-4]. Containment bypass frequency is the main contributor to LERF. Tube rupture, which is a function of flaw size and distribution, can be the main contributor to containment bypass frequency and hence LERF.

It has been found [B-1,B-3] that flaw-related LERF increments come principally from the following types of challenges:

Spontaneous steam generator tube rupture (SGTR) initiators, with resultant core damage. In these sequences, tube rupture causes the accident.

Steam-side depressurization events or anticipated transient without scram (ATWS) events, with resultant core damage, that may induce tube ruptures because of increased differential pressure across the tubes. Pressure-induced tube ruptures may occur in these circumstances and make the accident more severe, but they are not the original cause.

Core damage accidents due to other causes, during which flawed tubes are induced to fail either by increased pressure differentials at normal temperatures (caused by, for example, operator depressurization of the steam side or by stuck-open main steam safety valves), or at elevated temperatures following core heat-up. These are called High/Dry Sequences because the primary system remains at high pressure, while the secondary side dries out.

B.2 Method Used for the Risk Determination

Because it has been previously found [B-1,B-3] that the principal contributions to risk are from severe accidents, this study focuses on the High/Dry sequences. The risk assessment methodology is then used to calculate changes in LERF from these sequences over a number of operating cycles, as wearing of the steam generator tubes increases.

In Reference [B-2], the accident sequences for Plant A were divided among three characteristic timing groups. For Early Core Damage sequences, the core is estimated to uncover around 2 hours after accident initiation, due to the unavailability of both primary and secondary cooling. Typically, the complete loss of cooling is caused by the combination of the loss of all ac power and the unavailability or failure of the turbine-driven AFW pump (TDP). These sequences are initiated by transients, such as a station blackout, that cause or lead to loss of all onsite and off site power or the loss of actuation capability for all systems that could provide primary or secondary cooling. In addition, the turbine-driven AFW pump is also unavailable. Due to the total lack of cooling, MAAP 4.0.3 typically calculates that the steam generators dry out in about 1.5 hours and the core uncovers in about 2. hours.

A second timing category, the Mid Core Damage sequences, is based on the failure of both ac power and inverted ac power for instrumentation and control after the battery power supply fails. The AFW system relies on dc power to support steam generator level indication and also to enable the ADVs to be opened remotely. The loss of level indication is assumed to lead to failure of the AFW function and the core is estimated to uncover at about 12 hours after accident initiation. Such sequences are characterized by a loss of both off-site and on-site ac power, typically due to a seismic event that disrupts the electrical distribution system. Thus the charging, safety injection, RHR and motor-driven AFW pumps are unavailable. The core is initially cooled through the secondary system. The turbine-driven AFW pump provides water to the steam generators, which are depressurized to about 240 psig by dumping steam through the atmospheric dump valves. At 4 hours the batteries are assumed to be depleted and steam generator level indication is lost. In the IPE and IPEEE, the AFW system is assumed to fail at this time, leading to steam generator dry out at about 10 hours and core uncovering at about 12 hours. More realistic assumptions on AFW system operation typically lead to longer failure times.

Finally, a third timing category, the Late Core Damage sequences, is based on sequences where ac power is available, but the AFW system is unavailable for reasons other than loss of power and the TDP. This category did not contribute greatly to the risk in Plant A, and is not considered further here.

For the Early and Mid Core Damage sequences, the risk is calculated with the aid of several event trees that describe the possible variations in operator actions (with attendant human reliability assessment), accident progression, and tube rupture potential. The possible operator actions are modeled on Expanded Operator Action Trees (EOATs), the behavior of pumps, valves, and possible variations in thermal hydraulic behavior are modeled on Accident

Progression Event Trees (APETs). Tube failure probabilities (both from pressure- and temperature-induced rupture) are modeled on Tube Rupture Event Trees (TRETs). Input to the TRETs comes from calculations using the STEIN [B-6] and PROBFAIL [B-1] computer codes, for pressure- and temperature-induced probabilities, respectively.

Information flows from the EOATs to the APETs, and from the APETs to the TRETs. When the trees are all linked together it is possible to compute the Large Early Release Frequency (LERF).

B.3 Construction and Quantification of Event Trees

In this Section the methodology for constructing and quantifying the Expanded Operator Action Trees (EOATs), Accident Progression Event Trees (APETs), and the Tube Rupture Event Trees (TRETs) will be described. The EOATs consider the various operator actions associated with maintaining secondary side integrity while attempting to avert both core damage and thermal challenge to the steam generator tubes. The top events in the APETs focus on the failure potential of pumps and valves, and on thermal hydraulic conditions that can contribute to thermal challenge of the tubes. Failure potential of pumps and valves is discussed below; a more detailed treatment appears in [B-2]. The TRETs treat both pressure-induced and temperature-induced tube failures for the various accident sequences.

The EOATs and APETs were originally constructed and quantified in [B-2]; the EOATs were not changed for this study, but some minor changes were made to the APETs to better treat conditions where more than one steam generator is depressurized. The TRETs were originally constructed in Reference [B-1], but have been enlarged for the present study. The changes to the APETs and TRETs were necessary because the STEIN calculations indicate a high probability of pressure-induced tube ruptures at later cycles, when the degree of wear at anti vibration bars (AVBs) is calculated to be high.

B.4 EOAT and APET for Early Core Damage Sequences

The Early Core Damage EOAT and APET is shown on Figure B-2. It originally appeared in [B-1], where the top events are also defined and discussed. For convenience, this discussion is summarized below. Additional detail on the rationale for the split fractions assigned to each top event is provided in [B-1].

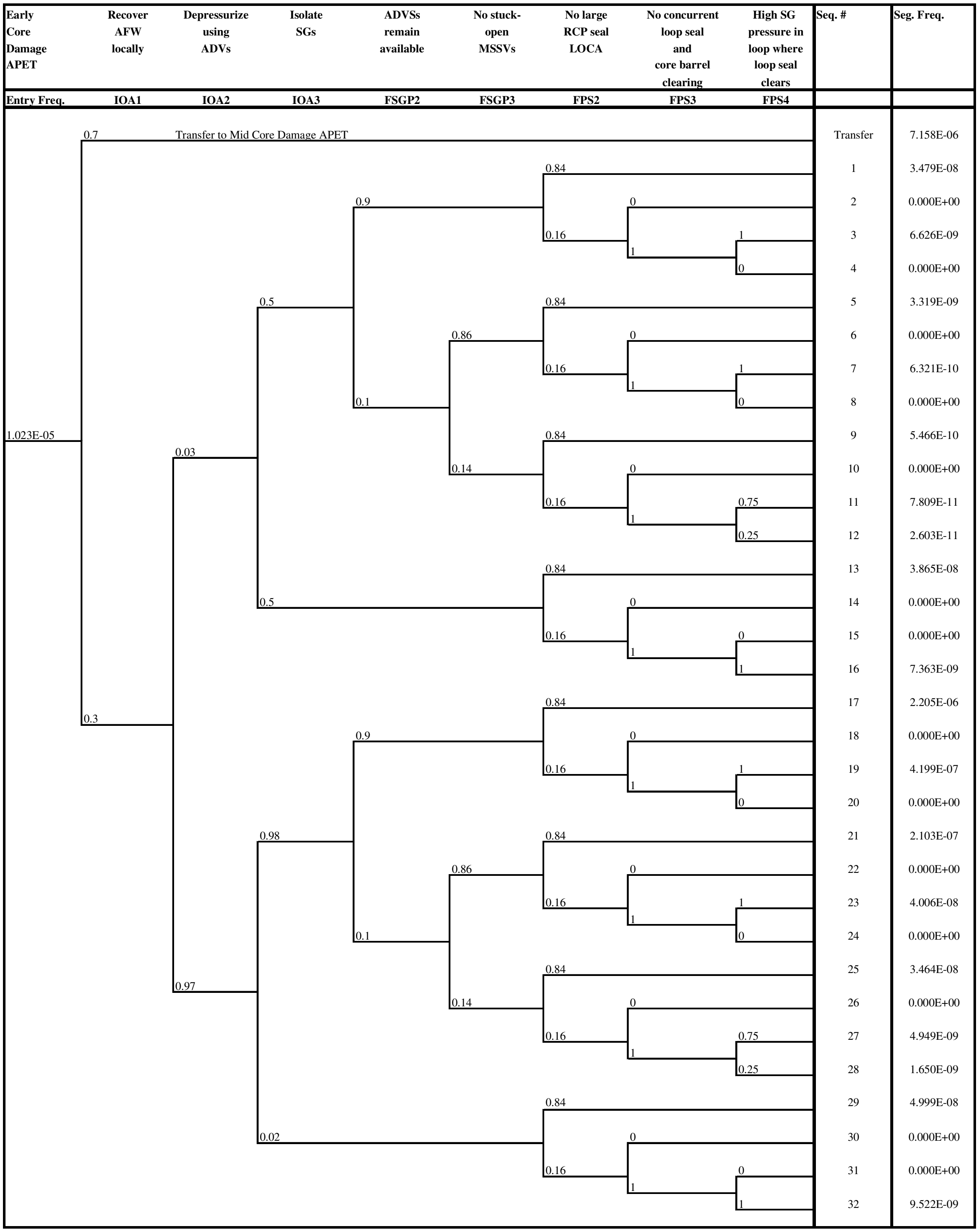

Figure B-1
Combined Early Core Damage EOAT and APET for Plant A

B.4.1 Entry Frequency (EARLY)

The sum of the high/dry frequencies for the Early Core Damage end states shown on Figure B-2 is 1.023E-05. It includes contributions from internal-, seismic-, and fire-induced initiators [B-1,B-2]. Typically, the complete loss of core cooling is caused by the combination of the failure of all ac power and the unavailability or failure of the turbine-driven auxiliary feed water (AFW) pump.

B.4.2 Recover AFW Pump Locally (IOA1)

This top event represents the likelihood of successful recovery of the turbine-driven AFW pump before the onset of core damage. This represents operator actions such as resetting an overspeed trip. The split fraction for successful recovery of the turbine-driven AFW pump within two hours is estimated [B-2] to be 0.7/0. The “recovered” sequences are transferred to the Mid Core Damage EOAT (see Figure B-3 below), with the auxiliary feed water pump recovered locally and the auxiliary turbine remaining available. The “failed” sequences remain on the Early Core Damage APET.

B.4.3 Depressurize Using ADVs (IOA2)

This top event is also the second event in the Early Core Damage EOAT. It represents the operator actions necessary to depressurize the RCS to a point where the RHR system can be aligned for shutdown cooling once ac power is restored. In this case the operators manually operate the 10% atmospheric dump valves (ADVs) to control steam pressure from either the control room or locally. Since the AFW pump has not been recovered locally, the split fraction of 0.03/0.97 represents the low likelihood that this adverse action will be taken by the operators .

B.4.4 Isolate the Steam Generators (IOA3)

The top event IOA3 assesses whether or not the operators ensure that all leak paths from the SGs are closed; for example, the operators ensure that the TDAFW turbine is tripped, MSIVs are closed and ADVs can be closed. Use of ADVs in a throttling mode remains as an operator control option for keeping the SG pressure below the MSSV relief points.

If the operators have previously depressurized using the ADVs, a failure probability of 0.5 is applied as a high dependence factor for a second error. If the operators have left the secondary side pressure high, the probability of operators failing to isolate the SGs is estimated to be about 2%.

B.4.5 ADVs Remain Available for Limiting High Pressure (FSGP2)

The ADVs are an important pressure boundary component of the secondary side of the steam generator. They provide operators with a means for controlling secondary pressure below the MSSV relief set points as long as they are available. Normal operations as well as potential failure modes of the ADVs need to be addressed to evaluate the potential for high or low pressure on the secondary side of the steam generators. The key failure modes of ADVs are that all valves close upon loss of control power or depletion of the air supply. These failure modes apply to the Mid Core Damage sequences. A less likely failure mode is that one or more of the ADVs will stick open due to mechanical failure.

Operation of the ADVs, after failing closed due to loss of control power or air supply, can be restored by local manual actions as discussed in [B-2]. Thus, failure to manually control the valves at a desired pressure, (including manually closing all ADVs to isolate the SGs) can lead to a demand on the main steam safety valves (MSSVs). The typical assumption in deterministic analysis is that the ADVs are closed and all demands for secondary relief are through the MSSVs when the pressure set point is reached. This assumption requires either the ADVs to be isolated by operator actionsor the ADVs to fail in a closed position following loss of control power or air supply. Any of these conditions can cause the secondary pressure to increase to the MSSV set points, causing the MSSVs to cycle. Human actions involving premature isolation (an error if inventory still exists in the SG s) increase the likelihood of MSSV demand.

If an ADV fails in the open position, the effect is the same as a MSSV sticking open, except that the operators can close block valves that isolate steam generator secondary by blocking the flow through the ADVs. Quantification of this condition reflects operator errors of omission in failing to close the ADV block valves. For the cases where the SGs are isolated, the split fraction is 0.9/0.1, representing the relatively low probability of errors of omission, as well as hardware failures that lead to MSSV cycling or directly to a low pressure condition [B-2]. For this top event, success means that the secondary side pressure remains below the set point pressure values of the MSSVs.

If the steam generators are not isolated (the failure branch for IOA3), then the secondary side pressure also remains below MSSV set points, and the secondary side is assumed to depressurize.

B.4.6 No Stuck-Open MSSVs (FSGP3)

This top event addresses the possibility that MSSVs may fail to re-seat after opening at their set point pressure. This pressure could be reached if the ADVs are closed and are no longer available to control pressure. There are two facets to this event. First, operational transient data evaluated in Appendix C of [B-2] suggest that there is a probability of failing to re-seat after the first lift of 4.5E-03 per demand, due to maintenance errors. For a four-loop plant the cumulative probability of failure to re-seat after the first lifts is 1.8E-02. Second, the MSSVs would be challenged many times in the course of a station blackout event in order to relieve the pressure. Even though the valves would be functioning within design parameters, there is a possibility that they would fail to re-seat due to excessive wear. The valve manufacturers (Crosby and Dresser) have obtained considerable test data on MSSVs. An analysis of data taken by EPRI for the Westinghouse Owners Group [B-7] reveals that 234 valve cycles were observed without any failures. One valve (a Crosby 6R10 MSSV) was tested over 90 times without failure, and showed relatively little evidence of wear. Between Crosby and Dresser, more than 1400 tests on MSSVs under prototypical conditions (including the 90 tests noted above) have been carried out without failure. One of Dresser's valves was tested more than 200 times without failure [B-7]. Since there were no failures, an estimate of the failure rate for any given cycle can be obtained from the formula [B-8]

P_{fail} = 0.55/1400 = 3.93E-04 per cycle.

The sequences analyzed with MAAP 4.0.3, discussed in Appendix B of [B-2], resulted in about 85 MSSV cycles per loop. Based on this assessment, the cumulative failure probability from 85 lifts of the MSSV with the lowest set point in its loop is

$$P_{fail} = 1 - (1 - 3.93x10^{-4})^{84}(1 - 4.5x10^{-3}) = 0.0374\,.$$

The likelihood that there would be no failures among the four loops is estimated by

$P_{success}$ = (1- 0.0374)^4 = 0.8586.

B.4.7 No large seal LOCAs (FPS2)

This top event refers to the possibility that large seal LOCAs (about 170 gpm per pump or higher) would develop subsequent to loss of component cooling water. The split fractions used here are derived from Table 5.4-2 of [B-9]. The new O-Ring case is used since these have been installed in Plant A's pump seals. MAAP analyses discussed in [B-2] indicate that, for small seal LOCAs, the pressure behavior in the RCS does not differ significantly from cases where no seal LOCAs were assumed. Only for larger seal LOCAs would it be expected that the RCS would depressurize sufficiently quickly to cause loop seal clearing. The information in [B-9] suggests that the likelihood of pump seal LOCAs of 170 gpm/pump and higher is about 0.16. Thus, the split fractions are 0.84/0.16, for all four loops.

B.4.8 No concurrent loop seal and core barrel clearing (FPS3)

This top event refers to the possibility that both a loop seal and the core barrel would clear, thus paving the way for a once-through natural circulation flow through a steam generator. If this were to occur with the corresponding secondary side depressurized, then it is likely that tube would rupture at high temperature, even if they were not degraded.

MAAP does not model the clearing of loop seals, and judgements on this phenomenon rely on published SCDAP/RELAP5 results. These calculations are inconsistent: in some plant analyses loop seal clearing is predicted to occur for seal LOCAs of 250 gpm/pump or larger whereas in other cases this was not predicted to occur. Another issue that complicates interpretation of these results is that NRC-sponsored calculations are run in such a way that the leakage rate at the time of the seal failure is set to 250 gpm whereas the original seal LOCA evaluations were based on the leak rate evaluated at nominal post-trip conditions. This change in assumption has the effect of substantially increasing the effective leak area over that calculated in support of the NUREG-1150 expert panels. Finally, MAAP results indicate that it is likely that the base of the core barrel will remain covered during the time frame of interest, even if a loop seal clears. For all these reasons, the split fractions shown on Figure B-1 for this top event are assumed to be 0.90/0.10.

B.4.9 High SG Pressure in Loop Where Loop Seal Clears (FPS4)

This top event determines the likelihood that a loop where a loop seal clears would be connected to a SG that would be either at high or low pressure. The split fractions are determined as follows. If no MSSVs fail to re-seat and if the SGs are isolated, then the SG in the affected loop remains at high pressure and the split fraction is 1/0. For sequences where a MSSV has failed to re-seat, it is most likely that only one SG is depressurized. Likewise, only one loop in the RCS would clear, if this were to happen at all. Thus, the likelihood of success for these cases is 0.75. Low secondary side pressure is already assured in all loops for sequences where the operators fail to isolate the SGs; for these cases the split fraction is 0/1 since low pressure in the affected loop is guaranteed

B.5 EOAT and APET for Mid Core Damage Sequences

The issues associated with constructing and quantifying the Mid Core Damage EOAT for Plant A, which accounts for operator actions and human reliability, are discussed in Section 3. A brief description of the top events and their quantification is given below; a detailed description appears in [B-2]. The EOAT is reproduced from [B-2] for convenience as Figure B-2.

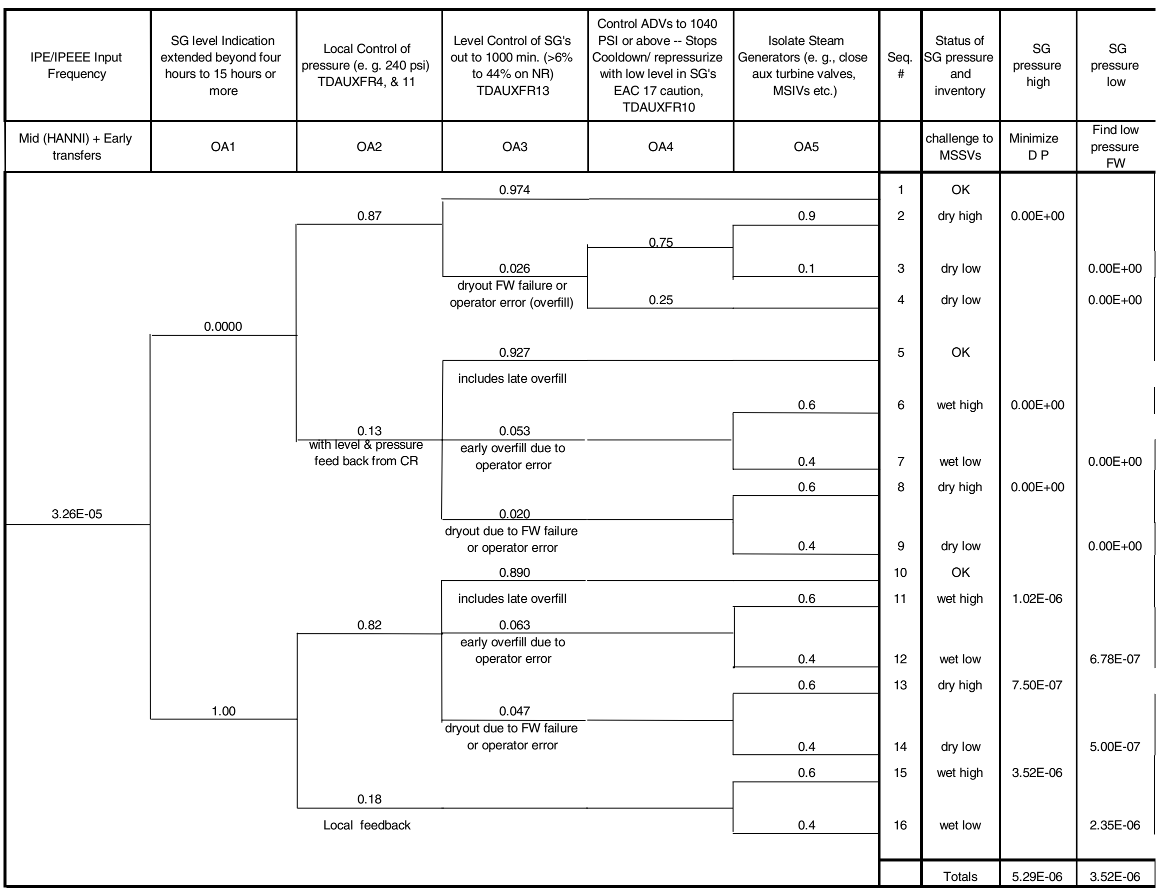

Figure B-2
Mid Core Damage EOAT for Plant A

The APET presented in two parts below on Figures B-3 and B-4 begins with a consolidation of the sequences in the EOAT, based on steam generator status. MAAP 4 analyses show that, if the steam generators remain at high pressure, the potential for thermal challenge differs depending upon whether dry out or overfill occurs. If the steam generators are at low pressure, however, the consequences are the same regardless of whether overfill occurs prior to dryout, since overfill tends to lead to the possibility of a stuck-open MSSV. The top events for the Mid Core Damage EOAT and APET are described below.

B.5.1 Input Frequency to EOAT from IPE/IPEEE

This is the sum of the frequencies of high/dry sequences from the Mid Core Damage sequences discussed in detail in [B-2], and those transferred from the Early Core Damage EOAT shown on Figure B-1 (sequences where the AFW pump was recovered locally). This combined frequency is 3.26E-06/RY.

B.5.2 Extended SG Level Indication (OA1)

This top event represents operator actions or plant modifications that extend the time when level indication is available. Absent extended level indication, failure of dc power means the local turbine operator must operate the SG feed water control valves without direct feedback on level. At best the operator can use mechanical pressure gauges, and changes in the turbine behavior to anticipate and infer overfill or dry out conditions. If dry out is imminent, the pressure may fluctuate and the turbine will slow. If overfill is occurring the turbine is expected to change sound, vibrate and stop when steam flow is interrupted or water slugs are ingested into the turbine. In either case, corrective actions are possible but are less likely to be successful than if an explicit indication of water level is available.

The split fraction of 0/1 assumes that the IPE assessment of battery life is true, and the probability of extending level indication beyond four hours without recovery actions is zero.

B.5.3 Local Pressure Control (OA2)

This top event represents control of SG pressure using the ADVs, either from the control room by setting the desired pressure, manually with a hand wheel, or by manual control using bottled air. It is discussed in detail in [B-2]. As shown on Figure B-2, if extended level indication were available the likelihood of success is estimated to be 0.87. Without extended level indication, the value drops to 0.82

B.5.4 Level Control of SGs for At Least 1000 Minutes (OA3)

This top event represents local actions for maintaining level control of SGs out to 1000 minutes. Based on MAAP calculations, this time is sufficient to ensure that the SG tubes will remain water-cooled to at least the mission time of 24 hours. Operators would slowly throttle feed flow to the SGs to match the reduction in decay heat with time. For this event the system is initially successful. The settings for the AFW system valves and control points are assumed to be established during the initial operating period, providing the operators with a history of RCS temperatures and pressures for the auxiliary turbine, and settings for level control valves and ADVs.

In Appendix A of [B-2], three supporting EOATs are used to evaluate the dry out or overfill potential. Consequently, triple branches result representing success, failure with early overfill due to operator error, and failure with dry out due either to feed water pump failure or operator error. Note that Figure B-2 has three different sets of values for OA3. The first set is assigned whenever extended level indication and local pressure control are both implemented. In this case, overfill would not occur and the failure branch of this top event represents a dried out SG. The second set is relevant when there is extended level indication but no local pressure control. The third set applies whenever there is no extended level indication but local pressure control is available.

B.5.5 Stop Cool Down and Repressurize SGs (OA4)

In the event of a SG dry out with good level indication, failure of OA4 represents dry out with pressure in the steam generator at about 240 psi and the RCS cooled. In this case the operators have two basic strategies: (1) isolate the SG flow paths, allowing the system to heat up and repressurize while trying to recover a high pressure water source, or (2) continue depressurizing the secondary side to utilize lower pressure injection systems (e. g., the diesel driven fire water pump). As shown on Figure B-2, the success probability is 0.75.

B.5.6 Isolate SGs by Closing ADVs (OA5)

This top event relates to control of SG pressure by the operating crew, given that level control has been lost. For the case where there is good level indication and local pressure control, but level control is somehow lost, the success probability is represented as 0.9. For other cases the procedures are less clear, and the success probability drops to 0.6.

B.5.7 Entry Frequencies to APET from EOAT

The sequences from the Mid Core Damage EOAT for Plant A, shown on Figure B-2, can be consolidated into four categories, based upon steam generator status. Note that EOAT sequences 1, 5, and 10 all have successful level control to 1000 minutes, do not lead to thermal challenge conditions within 24 hours, and thus do not transfer to the APET. Sequences 2, 8, and 13 result in a dry secondary side at high pressure. Sequences 6, 11, and 15 represent overfill conditions with the secondary side at high pressure. Sequences 3, 4, 9, and 14 result in a dry secondary side with the SGs at low pressure, either due to feed water failure or to operator error (either failure to isolate following SG overfill, or inability to control the pressure locally). Finally, sequences 7, 12, and 16 are such that the secondary side is at low pressure due to operator error. The APET, with its four entry points, is shown in two parts on Figures B-3 and B-4.

B.5.8 Number of Stuck-Open MSSVs from Liquid Challenge (SSGP3)

For those cases where SG overfill would occur at high pressure (designated as “wet, high” on Figure B-4), the MSSVs would be required to vent water. They are not designed for such conditions, but no data exist to evaluate the extent to which the valves would stick open, or whether the secondary side would subsequently depressurize. For this example, then, it is assumed that the MSSV in each loop at the lowest set point has a 50% likelihood (the “total ignorance” factor) of sticking open far enough to depressurize the steam generator. Since there are four steam generators in Plant A, it is necessary to compute the conditional probabilities of 0-4 steam generators being depressurized. This is because to conditional probabilities of pressure- and temperature-induced tube rupture are strong functions of the number of depressurized steam generators.

Boolean logic is applied to determine the probabilities of 0-4 MSSVs failing to re-seat after liquid challenge. For example, the overall conditional probability that at least one steam generator would depressurize is given by:

$$P_{fail} = 1 - P_{success} = 1 - (0.5)^4 = 0.9375$$

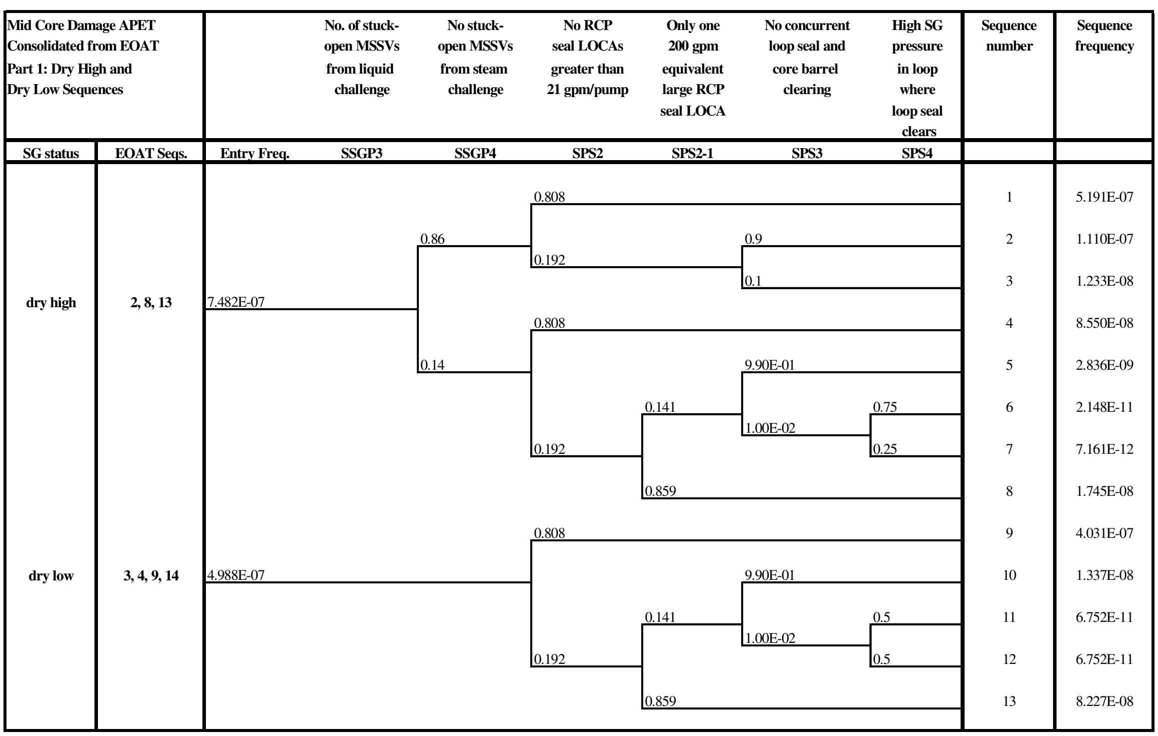

Figure B-3
Mid Core Damage APET for Dry High and Dry Low Sequences

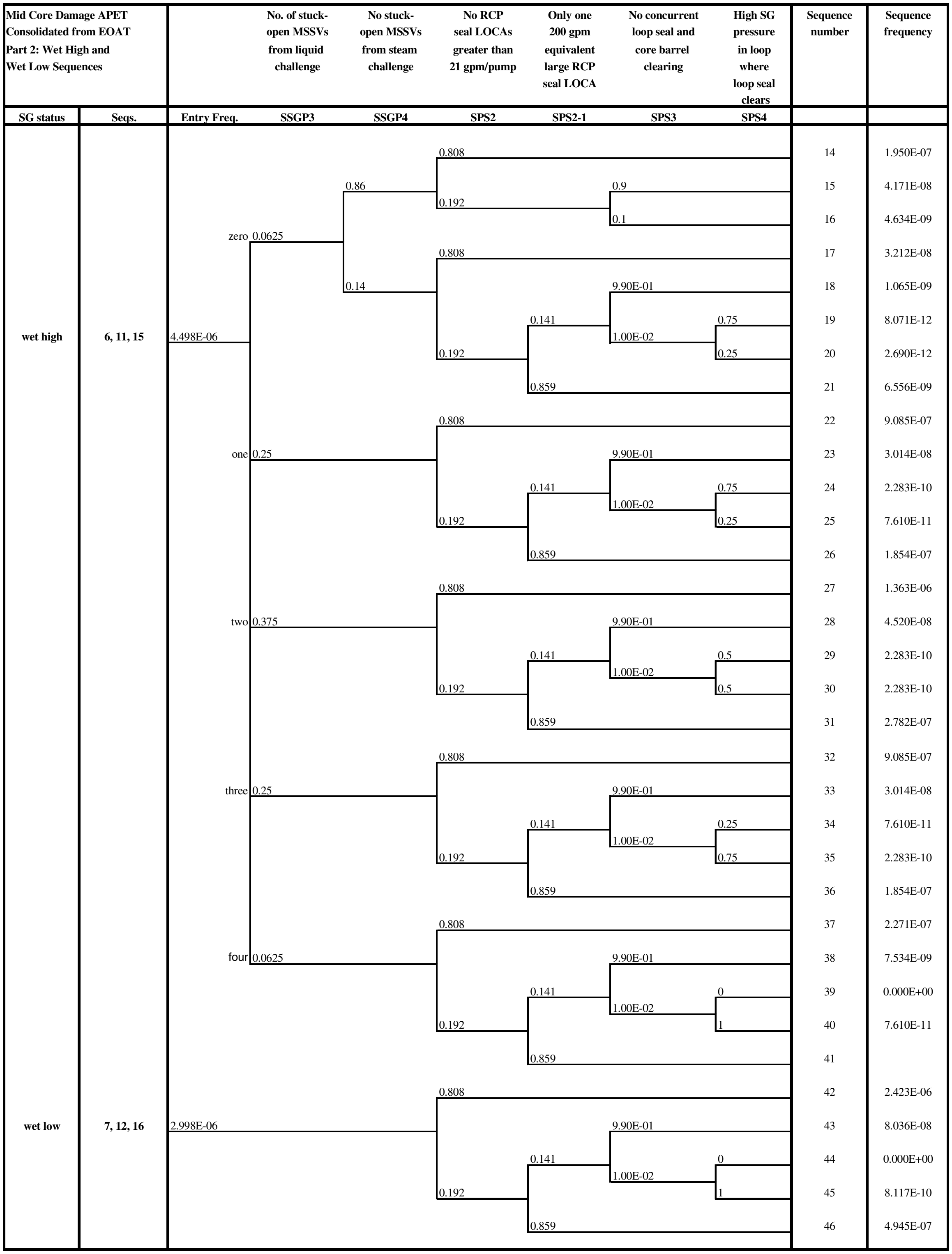

Figure B-4
Mid Core Damage APET for Wet High and Wet Low Sequences

The following table shows the failure probabilities derived from using this approach:

Number of stuck-open MSSVs	Conditional Probabilities
0	0.0625
1	0.25
2	0.375
3	0.25
4	0.0625

It is thus seen that there is a very high potential for more than one steam generator to become depressurized following MSSV failure to re-seat after liquid challenge. This is duly reflected on Figure B-4.

These values appear on Figure B-4 as various branches for top event SSGP3. The overall success probability (no stuck-open MSSVs) is only 0.0625. The remaining branches represent different levels of failure. As information becomes available, it may be possible to determine these probabilities with more certainty. As it is, the overall failure probability is very high, and further information is most likely to lead to a lower potential for applying high pressure to the SG tubes.

B.5.9 No Stuck-Open MSSVs from Steam Challenge (SSGP4)

This top event addresses the possibility that MSSVs may fail to re-seat after opening at their set point pressure. This pressure could be reached if the ADVs are closed and are no longer available to control pressure. For simplicity, the discussion for the Early Core Damage sequences, is assumed to apply to this top event as well, even though the number of MSSV lifts may differ somewhat.

B.5.10 No Large Seal LOCAs Greater Than 21 gpm per pump (SPS2)

This top event refers to the possibility that large seal failures would develop subsequent to loss of seal cooling. The split fractions used here are derived rom Table 5.4-2 of [B-9]. Reference [B-9] presents the results of expert judgement elicitation by the NRC, to support NUREG-1150 [B-10], on the issue of performance of pump seals during severe accident conditions. The experts determined the probabilities of developing significant leakage through the pump seals once they lost the ability to maintain restricted flow between the primary system and the containment. Two cases were considered, one for plants having RCP pump seals with O-rings not qualified for high-temperature conditions (“old O-rings”), and O-rings that are qualified under high-temperature conditions (“new O-rings”). The new O-rings have been installed in Plant A’s pump seals, so their values are used here.

Reference [B-9] states that leakage of 21 gpm through a pump seal would be expected, unless the pump seal would fail, either through elastomer failure, binding, or popping open. The experts assigned a probability of 0.808 that the leakage rate would be 84 gpm (21 gpm per pump). Thus, the split fractions aggregated for all four loops are 0.808/0.192. MAAP analyses discussed in [B-2] indicate that, for 21 gpm/pump seal LOCAs, the pressure behavior in the RCS does not differ significantly from cases where no seal LOCAs were assumed. Only for larger seal LOCAs would it be expected that the RCS would depressurize sufficiently quickly to allow for the possibility of loop seal clearing.

B.5.11 Only One 200 gpm Equivalent Large RCP Seal LOCA

Calculations with MAAP 4.0.3 for Mid Core Damage sequences with RCP seal LOCAs show that, for total leakage of 680 gpm or more (corresponding to 170 gpm seal LOCAs in each reactor coolant pump seal), the leakage rate from the RCS is so large that the reactor pressure vessel lower head is predicted to fail before the steam generator tubes become dry[B-2]. On the other hand, if the total leakage rate is about 200 gpm, thermal challenge to the tubes is a possibility. In [B-9], an aggregated seal LOCA probability of 0.027 is assigned by the experts to having total seal LOCA leakage in the 200-300 gpmrange, given a seal failure. For these cases the possibility of concurrent loop seal and core barrel clearing with dry SGs exists. The split fractions for the "success" branches are computed as 0.027/0.192=0.141. The "failure" branch split fractions (680 gpm total flow rate or higher) are thus 0.859.

B.5.12 No Concurrent Loop Seal and Core Barrel Clearing (SPS3)

This top event refers to the possibility that both a loop seal and the core barrel would clear, thus paving the way for a once-through natural circulation flow through a steam generator. MAAP results indicate that it is likely that the base of the core barrel will remain covered during the time frame of interest, even if a loop seal clears. Moreover, for leakage rates of 300 gpm or less, it is judged to be very unlikely that loop seal clearing would even occur. The split fractions shown on Figures B-2 and B-3 for this top event are thus 0.99/0.01.

B. 5.13 High SG Pressure in Loop Where Loop Seal Clears (SPS4)

This top event determines the likelihood that a loop where a loop seal clears would be connected to a SG that would be either at high or low pressure. The split fractions are determined as follows. For the dry high and wet high sequences, it is likely that only one SG is depressurized as a consequence of a MSSV sticking open (top events SSGP3 and SSGP4). Likewise, only one loop in the RCS would have its loop seal cleared, if this were to happen at all. Thus, the split fraction for the dry high and wet high sequences is 0.75/0.25. Low secondary side pressure is already assured in all loops for the dry low and wet low sequences, due to the operators' failure to isolate; for these the split fraction is 0/1.

B.6 Tube Rupture Event Trees (TRETs)

The Early Core Damage Event Tree and Mid Core Damage Tube Rupture Event Tree for Plant A are shown on Figures B-5 and B-6, respectively. Note that there are, respectively, ten and twelve entry points to the trees, based on conditions identified in the APETs shown on Figures B-2 – B-4. Each TRET includes top events for pressure-induced ruptures and thermally-induced creep rupture of the tubes.

Early Core Damage TRET Consolidated from APET		No pressure-induced tube ruptures	No temperature-induced tube ruptures	Sequence number	Sequence frequency	Large Early Release Frequency
Sequences/status	**Entry Freq.**	**NOPIRUP**	**NOTIRUP**		**Frequency**	**LERF**
Early CD: 9,25 SGs isolated, stuck-open MSSV no large seal LOCAs	3.519E-08	0.9955	0.981	1e	3.436E-08	
			0.019	2e	6.656E-10	6.656E-10
		0.0045		3e	1.583E-10	1.583E-10
Early CD: 13, 29 SGs not isolated no large RCP seal LOCAs	8.865E-08	0.982	0.926	4e	8.063E-08	
			0.074	5e	6.430E-09	6.430E-09
		0.018		6e	1.585E-09	1.585E-09
Early CD: 10, 26 SGs isolated, stuck-open MSSV large seal LOCAs	6.032E-09	0.9955	0.820	7e	4.924E-09	
			0.180	8e	1.081E-09	1.081E-09
		0.0045		9e	2.714E-11	2.714E-11
Early CD, 14, 30 SGs not isolated large seal LOCAs	1.520E-08	0.982	0.820	10e	1.224E-08	
			0.180	11e	2.686E-09	2.686E-09
		0.018		12e	2.717E-10	2.717E-10
Early CD: 12, 28 SGs isolated, 1 SG depr. large seal LOCAs LS & CB clearing	1.676E-10	0.9955	0.000	13e	0.000E+00	
			1.000	14e	1.668E-10	1.668E-10
		0.0045		15e	7.540E-13	7.540E-13
Early CD: 16, 32 SGs not isolated 4 SGs depr. large seal LOCAs LS & CB clearing	1.688E-09	0.982	0.000	16e	0.000E+00	
			1.000	17e	1.658E-09	1.658E-09
		0.018		18e	3.019E-11	3.019E-11
Early CD: 11, 27 High/dry/low high pressure in affected loop LS & CB clearing	5.027E-10	0.9955	0.007	19e	3.548E-12	
			0.993	20e	4.969E-10	4.969E-10
		0.0045		21e	2.262E-12	2.262E-12
Early CD: 1, 5, 17, 21 High/dry/high No large seal LOCAs	2.453E-06	0.9955	1	22e	2.442E-06	
			0	23e	0.000E+00	0
		0.0045		24e	1.104E-08	1.104E-08
Early CD: 2, 6, 18, 22 High/dry/high large seal LOCAs	4.205E-07	0.9955	1	25e	4.186E-07	
			0	26e	0.000E+00	0.000E+00
		0.0045		27e	1.892E-09	1.892E-09
Early CD: 3, 7, 19, 23 High/dry/high LS & CB clearing	4.266E-08	0.9955	1.000	28e	4.246E-08	
			0.000	29e	1.571E-12	1.571E-12
		0.0045		30e	1.920E-10	1.920E-10

Total Early LERF **2.839E-08**

Figure B-5
Early Core Damage TRET for Plant A (at 9.835 EFPY)

Mid Core Damage TRET Consolidated from APET		No pressure-induced tube ruptures	No temperature-induced tube ruptures	Seq. #	Seq. Freq.	Large Early Release Frequency
Sequences/status	Entry Freq.	NOPIRUP	NOTIRUP		Frequency	LERF
Mid CD: 4, 5, 17,18,22,23 SGs isolated 1 SG depressurized (stuck-open MSSVs)	1.060E-06	0.9955	0.981	1m	1.035E-06	
			0.019	2m	2.005E-08	2.005E-08
		0.0045		3m	4.771E-09	4.771E-09
Mid CD: 27,28 SGs isolated 2 SGs depressurized (stuck-open MSSVs)	1.408E-06	0.991	0.962	4m	1.343E-06	
			0.038	5m	5.252E-08	5.252E-08
		0.009		6m	1.264E-08	1.264E-08
Mid CD: 32,33 SGs isolated 3 SGs depressurized (stuck-open MSSVs)	9.387E-07	0.987	0.944	7m	8.743E-07	
			0.056	8m	5.179E-08	5.179E-08
		0.013		9m	1.261E-08	1.261E-08
Mid CD: 37, 38 SGs isolated 4 SGs depressurized (stuck-open MSSVs)	2.347E-07	0.982	0.926	10m	2.134E-07	
			0.074	11m	1.702E-08	1.702E-08
		0.018		12m	4.196E-09	4.196E-09
Mid CD: 42,43 SGs not isolated, zero or one large seal LOCA	2.503E-06	0.982	0.926	13m	2.277E-06	
			0.074	14m	1.816E-07	1.816E-07
		0.018		15m	4.475E-08	4.475E-08
Mid CD: 9,10 aux. turbine fails (two SGs depress.) zero or one large seal LOCA	4.164E-07	0.991	0.962	16m	3.972E-07	
			0.038	17m	1.553E-08	1.553E-08
		0.009		18m	3.739E-09	3.739E-09
Mid CD: 7,20,25 1 SG depr. LS & CB clearing	8.595E-11	0.9955	0.000	19m	0.000E+00	
			1.000	20m	8.557E-11	8.557E-11
		0.0045		21m	3.868E-13	3.868E-13
Mid CD: 12,30 2 SG depr. LS & CB clearing	2.958E-10	0.991	0.000	22m	0.000E+00	
			1.000	23m	2.932E-10	2.932E-10
		0.009		24m	2.656E-12	2.656E-12
Mid CD: 35 3 SG depr. LS & CB clearing	2.283E-10	0.987	0.000	25m	0.000E+00	
			1.000	26m	2.252E-10	2.252E-10
		0.013		27m	3.068E-12	3.068E-12
Mid CD: 40,45 4 SG depr. LS & CB clearing	8.878E-10	0.982	0.000	28m	0.000E+00	
			1.000	29m	8.720E-10	8.720E-10
		0.018		30m	1.587E-11	1.587E-11
Mid CD: 11,29 2 SG depr. high pressure in affected loop LS & CB clearing	2.958E-10	1.000	0.000	31m	0.000E+00	
			1.000	31m	2.958E-10	2.958E-10
		0.000		33m	0.000E+00	0.000E+00
Mid CD: 3,16 0 SG depressurized high pressure in affected loop LS & CB clearing	1.697E-08	0.9955	1.000	34m	1.689E-08	
			0.000	35m	6.250E-13	6.250E-13
		0.0045		36m	7.636E-11	7.636E-11
					Total Mid LERF	4.231E-07

Figure B-6
Mid Core Damage TRET for Plant A (at 9.835 EFPY)

B.6.1 Entry Points

The first entry point on the Early Core Damage TRET consolidates sequences 9 and 25 from the APET. For these sequences a steam generator is at low pressure following MSSV failure to re-seat. Additionally, no large RCP seal LOCAs have occurred in the RCS. The second entry point is for sequences 13 and 29 in the APET. For these sequences all SGs are depressurized because the operators have failed to isolate them, and there are no large RCP seal LOCAs. The third entry point combines sequences 10 and 26, which are characterized by failure of at least one MSSV to re-seat, and large RCP seal LOCAs. The fourth entry point includes sequences 14 and 30, for which all SGs are depressurized due to failure to isolate. There are also RCP seal LOCAs.

The fifth, sixth, and seventh entry points are for cases where there are large RCP seal LOCAs and concurrent loop seal and core barrel clearing. Sequences 12 and 28, characterized by at least one stuck-open MSSV, and a depressurized SG in the loop where the loop seal clears, comprise the fifth entry point. The sixth entry point, for sequences 16 and 32, represents all four SGs being depressurized due to failure to isolate. The seventh entry point is for sequences 11 and 27, for which the cleared loop seal is in a loop where the SG is still pressurized, although dried out. Unidirectional flow is still present, however, so that there is some potential for creep rupture of the tubes.

Entry points 8-10 are for high/dry/high sequences. These are new branches that have been added since [B-1] was published. They have been added for this study in order to accurately treat conditions where the potential for pressure-induced tube rupture is high.

The first entry point on the Mid Core Damage TRET consolidates sequences 4, 5, 17, 18, 22, and 23 from Figures B-2 and B-3. For these sequences one SG is at low pressure following MSSV failure to re-seat. Additionally, any large RCP seal LOCAs that have occurred in the RCS did not result in leakage of more than 300 gpm and did not lead to concurrent loop seal and core barrel clearing. The next three entry points differ from the first one in that either two, three, or four steam generators, respectively, are depressurized due to MSSVs failing to re-seat following liquid challenge. The fifth entry point consolidates sequences where all four loops are depressurized because the SGs were not isolated by the operators. For the sixth entry point the auxiliary turbine has failed and the two SGs supplying steam to it are thus depressurized. The remaining entry points consolidate sequences that lead to concurrent loop seal and core barrel clearing. Entry points 7-10 represent sequences where there is low pressure in the steam generators connected to the loop where the loop seal clears, for 1-4 depressurized loops, respectively. Entry point 11 is for sequences where there are two depressurized steam generators, and high pressure in the steam generator connected to the loop where the loop seal clears. Entry point 12 represents sequences where all of the loops are pressurized, but there is loop seal clearing in one of the loops.

B.6.2 No Pressure-Induced Tube Ruptures (NOPIRUP)

This top event treats the likelihood that one of the steam generator tubes worn at the AVBs would rupture due to the imposition of a large differential pressure. This would likely occur prior to core damage, due either to the inability or failure of the operators to isolate the SGs, or to the failure of a MSSV to re-seat after being challenged, either by liquid or by steam.

The values shown on the trees are for the 9.835 EFPY case shown on Table B-1 for 1-4 depressurized steam generators. Note that Table B-1 shows failure probabilities, which appear on Figures B-5 and B-6 as failure (downward) branches. The failure probability for one depressurized steam generator is the burst probability for a pressure differential of 2650 psid, at the end of the cycle. The values shown on Table B-1 for the various cycles were obtained by using the STEIN code.

The conditional probability of pressure-induced tube rupture was calculated by STEIN to be less than 0.0001/yr for the cycles up to and including 8.43 EFPY. It then rapidly increased over the following cycles, becoming very significant from 11.24 EFPY onward.

When more than one steam generator is depressurized the probability of success is

$$P_{NOPIRUP(n)} = (1-P_{Pfail})^n,$$

where P_{Pfail} is the probability of pressure-induced tube rupture in a given depressurized steam generator, and n is the number of depressurized loops.

B.6.3 No Temperature-Induced Tube Ruptures (NOTIRUP)

This top event treats the likelihood that one of the steam generator tubes worn at the AVBs would fail due to creep rupture at high temperature. A number of factors influence this possibility; these are discussed in detail in [B-1], where the methodology for calculating thermally induced tube failures is presented. The values shown on the trees are for the 9.835 EFPY case shown on Table B-1. The temperature-induced probabilities shown on Table B-1 were determined by using the PROBFAIL code, which had input from the MAAP and STEIN codes (see Appendix A).

Just as for pressure-induced tube ruptures, when more than one steam generator is depressurized the probability of successfully averting temperature-induced tube ruptures is given by

$$P_{NOTIRUP(n)} = (1-P_{Tfail})^n.$$

where P_{Tfail} is the probability of temperature-induced tube rupture in a given depressurized steam generator, and n is the number of depressurized loops.

Table B-1
Conditional Probabilities of Pressure- and Temperature-Induced Failure in Worn Tubes

Conditional Probabilities of Tube Rupture	**1.405 EFPY**	**2.805 EFPY**	**4.215 EFPY**	**5.62 EFPY**	**7.025 EFPY**	**8.43 EFPY**	**9.835 EFPY**	**11.24 EFPY**	**12.645 EFPY**
Pressure-induced rupture, 1 SG depressurized	<0.0001	<0.0001	<0.0001	<0.0001	<0.0001	<0.0001	0.0045	0.46	0.86
Pressure-induced rupture, 2 SGs depressurized	<0.0002	<0.0002	<0.0002	<0.0002	<0.0002	<0.0002	0.0090	0.708	0.980
Pressure-induced rupture, 3 SGs depressurized	<0.0003	<0.0003	<0.0003	<0.0003	<0.0003	<0.0003	0.0134	0.843	0.997
Pressure-induced rupture, 4 SGs depressurized	<0.0004	<0.0004	<0.0004	<0.0004	<0.0004	<0.0004	0.0179	0.915	1.000
Temperature-induced rupture, 1 SG depressurized	<1E-6	<1E-6	<1E-6	4.30E-06	6.3E-05	0.0017	0.019	0.069	0.076
Temperature-induced rupture, 2 SGs depressurized	<1E-6	<1E-6	<1E-6	8.6E-06	0.0001	0.0034	0.0376	0.133	0.146
Temperature-induced rupture, 3 SGs depressurized	<1E-6	<1E-6	<1E-6	1.3E-05	0.0002	0.0051	0.0559	0.193	0.211
Temperature-induced rupture, 4 SGs depressurized	<1E-6	<1E-6	<1E-6	1.7E-05	0.0003	0.0068	0.0739	0.249	0.271
Early CD, large RCP seal LOCAs, 1 SG depressurized	2.E-05	6.5E-05	3.8E-04	0.0024	0.013	0.064	0.18	0.28	0.29
Early CD, large RCP seal LOCAs, 2 SGs depressurized	4.1E-05	1.3E-04	7.5E-04	0.0049	0.026	0.13	0.36	0.52	0.54
Early CD, large RCP seal LOCAs, 4 SGs depressurized	5.7E-07	1.7E-06	1.2E-05	1.2E-04	0.0012	0.021	0.18	0.48	0.51
LS & CB clearing, affected loop SG depressurized, SG tube in affected loop fails	1	1	1	1	1	1	1	1	1
LS & CB clearing, all SGs pressurized, SG tube in affected loop Fails	<1E-6	<1E-6	<1E-6	<1E-6	<1E-6	<1E-6	3.70E-5	0.037	0.29
LS & CB clearing, affected loop SG pressurized, unaffected loop SGs depressurized, SG tube in affected loop fails	<1E-6	<1E-6	<1E-6	<1E-6	<1E-6	8.60E-06	0.0017	0.12	0.54
LS & CB clearing, affected loop SG pressurized, unaffected loop SGs depressurized, SG tube in unaffected loop fails	<1E-6	<1E-6	<1E-6	<1E-6	1.00E-6	1.40E-4	0.0054	0.037	0.032

B.6.4 Sequence Frequencies and Large Early Release Frequencies

The frequency of every branch is listed in the TRETs shown on Figures B-4 and B-5. Many of the branches, however, represent sequences where neither pressure-induced nor temperature-induced tube ruptures would occur. To get the total LERF the contributions from each branch representing tube rupture are summed.

For the example shown on Figures B-4 and B-5, the total LERF at 9.835 EFPY is about 4.54E-07/reactor-year. The major contributors are sequences 14, 5, 8, and 15 from the Mid Core Damage TRET. Each of these sequences involves multiple steam generator depressurization and temperature-induced tube ruptures. The loop seal and core barrel clearing are negligible contributors in this example. Pressure-induced tube rupture sequences contribute about 20% to the LERF.

B.7 Results

In this section, the results of using the risk assessment methodology for the various cycles are presented. The LERF at the end of each cycle, as well as the changes in LERF from the first cycle are shown, in order to assess the risk impact from increased wearing of the steam generator tubes.

The results are obtained by utilizing an Excel Spreadsheet that links the EOATs, APETS, and TRETs. The base-case split fraction values for the EOATs and APETS are as shown on Figures B-1 – B-3. The tube rupture probabilities that are input to the TRETS were obtained from STEIN and PROBFAIL calculations, and are listed in Table B-1 for all of the cycles considered. Results from the calculations are shown on Table B-2.

Table B-2
LERF and ΔLERF as a Function of EFPY

EFPY	LERF	ΔLERF
1.405	6E-9	---
2.805	6E-9	<1E-9
4.215	6E-9	<1E-9
5.62	6E-9	<1E-9
7.025	8E-9	1E-9
8.43	4E-8	3E-8
9.835	5E-7	4E-7
11.24	7E-6	7E-6
12.645	9E-6	9E-6

The results on Table B-2 show very small values of LERF and ΔLERF until 9.835 EFPY. Then, very rapid increases occur, due to a rapid increase in pressure-induced tube failure probability. Examination of Table B-1 reveals it increases very rapidly after 8.43 EFPY. The ΔLERF up until 8.43 EFPY is acceptable under Regulatory Guide 1.174 guidelines, whereas the ΔLERF up until 9.835 EFPY may not be acceptable.

Table B-3 gives a breakdown of the contributions to LERF over the various inspection intervals (i.e., operating times from RFO 7 without inspection). The second column of the table shows the total LERF, which is the sum of the frequencies of all of the sequences contributing to LERF. The third, fourth, and fifth columns show, respectively, the contributions to LERF from pressure-induced tube rupture, temperature-induced tube rupture in sequences with intact loop seals, and the contributions from sequences with temperature induced rupture with concurrent loop seal and core barrel clearing. If concurrent loop seal and core barrel clearing occurs and the affected loop steam generator is also depressurized, the tubes are calculated to fail prior to hot leg failure with virtual certainty. In such sequences, thermally-induced rupture is guaranteed provided that one or more tubes do not fail earlier in the sequence due to pressure-induced rupture – pressure-induced rupture is unlikely except for the longer inspection intervals where tube wear is significant. Thus, the values shown in the fifth column are constant until 11.24 EFPY. They decrease thereafter because the contributions from pressure-induced tube rupture sequences become dominant, reducing the contribution from thermally-induced rupture.

For the shorter inspection intervals the pressure-induced tube rupture probabilities are reported by STEIN as <1.0E-04/reactor-year (see Table B-1). For these cases a value of 1.0E-04 was conservatively input to the spreadsheet for a given steam generator. This value was used directly for the sequences where only one steam generator is depressurized, and is also used to calculate the pressure-induced tube rupture probabilities when more than one steam generator is depressurized. The same logic was used for the actual values reported for the longer inspection intervals. Until the value calculated by STEIN exceeds 1.0E-04/reactor-year, the contribution from pressure-induced tube rupture sequences remains constant at 2E-09/reactor-year. It then increases consistent with the value from STEIN, and eventually is the major contributor to LERF.

For the first few EFPYs after the end of Refueling Outage 7 (RFO 7) the total LERF is very small and is dominated by the sum of the frequencies of sequences characterized by concurrent loop seal and core barrel clearing. Moreover, LERF changes very little from cycle to cycle until 8.43 EFPY have elapsed from the end of RFO 7. From 7.025 EFPY to 8.43 EFPY there is a noticeable increase in the frequencies of the sequences characterized by temperature-induced tube ruptures. Note that, up to 8.43 EFPY, the frequencies of the sequences characterized by pressure-induced tube rupture have not increased.

The largest increase in LERF occurs between inspection intervals of 8.43 and 9.835 EFPY, and results from the change in the temperature-induced tube rupture probabilities. As can be seen in Table B-1, they increase by more than an order of magnitude over this period. The risk impact of this change is an increase of about 3.2E-07/reactor-year in the frequency of temperature-induced tube rupture sequences over this period (see Table B-3). The impact of the increase in pressure-induced tube failure probability is greatest between inspection intervals of 9.835 and 11.24 EFPY, as can also be seen on Table B-3. Note that the pressure-induced tube rupture sequences (PISTGR) dominate the LERF from 11.24 EFPY on. Consequently, the contributions from the sequences characterized by temperature-induced tube rupture decrease (because the tubes would likely have failed already from temperature-induced rupture). Although the results on Table B-3 show a reduction in the contributions from the temperature-induced failure sequences, the total induced tube failure probability continues to increase.

Table B-3
Contributions to LERF from Pressure-Induced and Temperature-Induced Sequences

EFPY	LERF	PISTGR	TISTGR/NLSC	TISTGR/LSC
1.405	6E-9	2E-9	<1E-9	4E-9
2.805	6E-9	2E-9	<1E-9	4E-9
4.215	6E-9	2E-9	<1E-9	4E-9
5.62	6E-9	2E-9	<1E-9	4E-9
7.025	8E-9	2E-9	2E-9	4E-9
8.43	4E-8	2E-9	3E-8	4E-9
9.835	5E-7	1E-7	4E-7	4E-9
11.24	7E-6	7E-6	2E-7	2E-9
12.645	9E-6	9E-6	2E-8	3E-9

It should be noted that, in all cycles, the contributions from sequences with concurrent loop seal and core barrel clearing are small. As mentioned in Section B.4.8, a significant difference of opinion still exists between the Industry and the NRC on this issue, and for this reason a sensitivity study has been carried out in order to determine the effects of using the NUREG-1570 [B-3] assumptions on loop seal clearing. By setting the probability of concurrent loop seal and core barrel clearing to unity when large RCP seal LOCAs occur, as was assumed in NUREG-1570, the results shown on Table B-4 are obtained.

If the NUREG-1570 assumptions are used the LERF is already 2.05E-07/reactor-year even with no appreciable AVB wear. This is because the PROBFAIL results indicate a tube failure probability of unity when a steam generator connected to the affected loop is depressurized (i.e., even pristine tubes would fail); similar results were obtained in NUREG-1570. As the AVB wear progresses the LERF approaches that of the Base Case. More importantly, the values of Δ-LERF are close between the NUREG-1570 case and the Base Case over all of the cycles. Just as for the base case, ΔLERF does not approach Regulatory Guide 1.174 guidelines until 9.835 EFPY have elapsed.

Table B-4
Effect of Using NUREG-1570 Assumptions on Concurrent Loop Seal and Core Barrel Clearing

EFPY	LERF (Base Case)	ΔLERF (Base Case)	LERF (NRC LSC)	ΔLERF (NRC LSC)
1.405	6E-9	---	2E-7	---
2.805	6E-9	<1E-9	2E-7	<1E-9
4.215	6E-9	<1E-9	2E-7	<1E-9
5.62	6E-9	<1E-9	2E-7	<1E-9
7.025	8E-9	1E-9	2E-7	1E-9
8.43	4E-8	3E-8	2E-7	3E-8
9.835	5E-7	4E-7	6E-7	4E-7
11.24	7E-6	7E-6	7E-6	7E-6
12.645	9E-6	9E-6	9E-6	9E-6

B.8 List of Aconyms

ADV	atmospheric dump valves
AFW	auxiliary feed water
APET	Accident Progression Event Tree
ARC	alternate repair criteria
ATWS	anticipated transient without scram
AVB	anti vibration bar
CDF	core damage frequency
CLB	current licensing basis
ECCS	emergency core cooling system
EFPY	equivalent full-power years
EOAT	Expanded Operator Action Tree
EPRI	Electric Power Research Institute
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination of External Events
LERF	large early release frequency
ΔLERF	change in large early release frequency
LOCA	loss-of-coolant accident
MAAP	computer program for severe accident analysis
MSSV	main steam safety valve
PRA	Probabilistic Risk Assessment
PROBFAIL	computer program to estimate the probability of temperature-induced steam generator tube ruptures
RCP	reactor coolant pump

RCS	reactor coolant system
SG	steam generator
SGTR	steam generator tube rupture
STEIN	computer program to estimate the probability of pressure-induced steam generator tube ruptures
TDAFW	turbine-driven auxiliary feed water
TDP	turbine-driven auxiliary feed water pump
TRET	Tube Rupture Event Tree

B.9 References

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C
LEAK AND BURST DATA FOR MONTE CARLO ANALYSIS OF AVB WEAR

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 [11]:

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

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 C-1 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 4-4.

Although leakage is not relevant for this example because the structural limit (SL) is far from through-wall, leak rate data is a required input into STEIN. Consequently, hypothetical leak rate data, presented in Table C-2, were input into STEIN.

Table C-1
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 C-2
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				

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