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Risk-Informed Inservice Inspection Evaluation Procedure

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REPORT SUMMARY

Risk-Informed Inservice Inspection Evaluation Procedure

Today, operating nuclear power plants rely on the implementation of ASME Section XI inservice inspection (ISI) programs for integrity management of Class 1, 2, and 3 systems and components. The evaluation procedure in this guide provides a practical approach that can be consistently applied by nuclear plant personnel to identify risk-significant pipe segments, define the elements that are to be inspected within these risk-significant segments and identify appropriate inspection methods.

INTEREST CATEGORIES

Piping, reactor vessel, and internals
Risk and reliability
Nondestructive examination

KEYWORDS

ASME Section XI
Inservice inspection
Risk-informed inservice inspection
Piping

BACKGROUND The scope for ASME Section XI ISI programs is largely based on deterministic results contained in design stress reports. These reports are normally very conservative and may not be an accurate representation of failure potential. Service experience has shown that failures are due to either corrosion or fatigue and typically occur in areas not included in the plant's ISI program. Consequently, nuclear plants are devoting significant resources to inspection programs that provide minimum benefit.

As an alternative, significant industry attention has been devoted to the application of risked-based selection criteria in order to determine the scope of inservice inspection (ISI) programs at nuclear power plants. Preliminary EPRI studies indicate that the application of these techniques will allow operating nuclear plants to reduce the examination scope of current ISI programs by as much as 60% to 80%, significantly reduce costs, and continue to maintain high nuclear plant safety standards.

OBJECTIVES The goal of the EPRI risk-based inspection program is to advance the development of risk technologies and implement these technologies to establish effective piping integrity management programs, reduce industry and regulatory burden, and continue to maintain plant safety. With this goal in mind, the following objectives guided the development of the methodology presented in this report. First, these methodologies should be practical, cost effective, an capable of being applied by utility engineers without dependency on outside consultants. Secondly, the process should integrate supplemental inspection programs that are currently outside the scope of ASME Section XI. Finally, the process should include guidance that will help utilities select and implement appropriate examination methods.

APPROACH The EPRI risk-informed selection procedure represents a traditional application of risk-based processes. A blended approach, that combines probabilistic safety assessment (PSA) and deterministic insights in support of the application, is used. The PSA insights employed are founded on the logic structure of a plant's PSA. This logic structure includes the fault trees and event tree models, the failure combinations causing undesired events, and success paths preventing undesired events. This process is consistent with the guiding principles set forth in the EPRI PSA Application Guideline, TR-105396.

The evaluation process includes: system and evaluation boundary identification, failure modes and effects analysis (FMEA), risk evaluation, and selection of inspection locations and examination methods. System identification includes the selection of systems for analysis and the identification of evaluation boundaries and functions.The FMEA consists of a consequence evaluation and degradation mechanism evaluation. These results are used to divide the system into piping segments, which are determined to have common degradation mechanisms and failure consequences. The key to this approach is grouping individual segments into one of three risk regions - High, Medium, or Low. The number of elements examined as part of the RBISI program is based on the risk region for the risk significant segments (High or Medium), and will be a percentage of the total number of elements in each risk region. The selection for examination of specific elements within a segment is based on the degradation mechanism, as well as inspection cost, radiation exposure, and accessibility. Inspection for cause process is then implemented to ensure that appropriate examination methods, procedures, acceptance criteria, and evaluation standards are applied to address the degradation mechanisms of concern.

RESULTS These procedures are expected to be refined and improved through ongoing PWR and BWR application studies. The pilot application studies will be completed in 1996 and a final report will be published incorporating the lessons learned. The process identifies those areas of the plant that are more safety significant, the number of inspections that must be performed, and provides a consistent set of criteria that the plant personnel can apply to select the actual inspection locations. Secondly, the process effectively integrates service experience and existing supplemental integrity management programs at the plant. Examples of these include: IGSCC, flow-accelerated corrosion, etc. Finally, the risk-based selection process should be coupled with a sound "inspection for cause" program. This way the process will not only identify the risk important areas of the plant, but will also define the appropriate examination methods, procedures, acceptance criteria, and evaluation standards necessary to address the degradation mechanisms of concern.

EPRI PERSPECTIVE For many nuclear plants, implementation of a risk-informed ISI program is expected to result in cost saving of $200,000 to $300,000 per outage. However, for most plants, the implementation of a risk-informed inspection program will depend on demonstrating that these cost savings will recover implementation costs within 1-2 operating cycles. Therefore, it is essential that the procedures developed are not only technically sound but are practical and cost effective. By doing so, the industry can effectively reduce operation costs and improve reactor safety.

PROJECT

Work Order 3230

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System and Component Integrity Program
Nuclear Power Group

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ABSTRACT

This report describes evaluation procedures for using risk to define inspection locations for safety significant piping in nuclear power plants. PSA insights, deterministic evaluations, and plant service experience are integrated in a practical, easy-to-use format. PSA insights are based on the logic structure used in the existing plant PSA. These procedures are consistent with the guiding principles set forth in the EPRI PSA Applications Guideline and NEI guidelines for risk-based inservice inspection.

The risk-informed inspection procedures in this report are intended to support ongoing BWR and PWR pilot plant application studies. The results and lessons learned from these application studies will be incorporated into a final report that will be published at the end of 1996.

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INTRODUCTION

1.1 Background

Today, operating nuclear power plants rely on the implementation of ASME Section XI [32] inservice inspection (ISI) programs for integrity management of Class 1, 2, and 3 systems and components. The scope of these ISI programs is largely based on deterministic results contained in design stress reports. These reports are normally very conservative and may not be an accurate representation of failure potential. Service experience has shown that failures are due to either corrosion or fatigue and typical occur in areas not included in the plant's ISI program. Consequently, nuclear plants are devoting significant resources to inspection programs that provide minimum benefit.

As an alternative, significant industry attention has been devoted to the application of risked-based selection criteria in order to determine the scope of inservice inspection (ISI) programs at nuclear power plants. Preliminary EPRI studies [10, 11] indicate that the application of these techniques will allow nuclear plants reduce the examination scope of current ISI programs by as much as 60% to 80%, significantly reduce costs, and continue to maintain high nuclear plant safety standards. Similar results have been obtained in earlier studies funded by the Nuclear Regulatory Commission (NRC) [14, 15] and the Westinghouse Owners Group (WOG) [17]. To date these studies have been limited to piping.

ASME Section XI established the Working Group on the Implementation of Risk-Based Inservice Inspection. Its charter is to study the application of risk-based selection criteria to define the scope of inservice inspection programs, and develop the necessary code changes to support its implementation. A code case [16] has been prepared to in order to support ongoing industry risk-based inspection pilot studies. ASME approval of this code case is expected in 1996.

In addition, the Nuclear Energy Institute (NEI) is currently developing an industry guideline for the implementation if risk-based inspection. This guideline identifies those fundamental principles important to all risk-based inspection activities. A draft of this guideline [4] has been submitted to the NRC for their review.

1.2 Objectives

The goal of the EPRI risk-based inspection program is to advance the development of risk technologies and implement these technologies to establish effective piping integrity management programs, reduce industry and regulatory burden, and continue to maintain plant safety. With this goal in mind, our objectives were quite simple. First and foremost, the risk evaluation approach must be technically sound, practical, and capable of being consistently applied by plant personnel. To the maximum extent possible, the results should be "process driven" and not depend on a panel of experts. Therefore, the procedures should provide selection criteria that will identify all safety significant piping in the plant, identify the number of inspections that must be performed, and provide a consistent set of rules that the plant personnel can apply to select the actual inspection locations. This way the primary role of the plant review team (e.g. expert panel) will be to verify the process results are consistent with plant service experience.

Secondly, the process should effectively integrates service experience and existing supplemental integrity management programs at the plant. Examples of these include: IGSCC, flow-accelerated corrosion, etc.

Finally, the risk-based selection process should be coupled with a sound "inspection for cause" program. This way the process will not only identify the risk important areas of the plant, but will also define the appropriate examination methods, procedures, acceptance criteria, and evaluation standards necessary to address the degradation mechanisms of concern.

1.3 Approach

The EPRI risk-informed selection procedure represents a traditional application of risk-based processes. A blended approach, that combines PSA and deterministic insights in support of the application, is used. The PSA insights employed are founded on the logic structure of a plant's PSA. This logic structure includes the fault trees and event tree models, the failure combinations causing undesired events, and success paths preventing undesired events. This process is consistent with the guiding principles set forth in the EPRI PSA Application Guideline. [2] The evaluation process includes: system and evaluation boundary identification, failure modes and effects analysis (FMEA), risk evaluation, and selection of inspection locations and examination methods. PWR and BWR pilot application studies will be used to validate these procedures.

Systems are selected for evaluation in accordance with the requirements specified in the NEI guideline [4]. The exact method used to define the scope of these pilot studies is described in Section 2. The FMEA consists of a consequence evaluation (Section 3) and degradation mechanism evaluation (Section 4). These results are used to divide the system into piping segments, which are determined to have common degradation mechanisms and failure consequences.

The risk evaluation procedures in Section 5 categorize the risk of each segment as High, Medium, or Low. The integrity of the piping segments in the low risk categories will continue to be monitored by periodic pressure/leak testing, operator walkdowns, and in place leakage monitoring programs. For high and medium risk piping segments, the scope of inspections and selection of inspections locations is then defined according to the guidelines in Section 6.

For each inspection location, an inspection for cause program is implemented to ensure that appropriate examination methods, procedures, acceptance criteria, and evaluation standards are applied to address the degradation mechanisms of concern. These requirements are specified in Section 7.

The procedures contained in this interim report meet these objectives and are intended to support ongoing PWR and BWR pilot application studies. These procedures are expected to be refined and improved through these application studies. The pilot application studies will be completed in 1996 and a final report will be published incorporating the lessons learned.

2

OVERVIEW OF EPRI METHODOLOGY

2.1 Basis for EPRI Methodology

As stated in the previous section, the goal of this EPRI project was to develop and implement risk-informed inservice inspection (RISI) technology in order to establish an effective piping integrity management program. Currently, the majority of risk-informed processes being developed are utilizing existing PSA models and importance measures, as defined in the EPRI PSA Application Guide's quantitative criteria [2]. Given that piping elements are highly reliable and traditionally are not part of the PSA, it is difficult to visualize an unmodified PSA application in the RISI process. As stated in SECY-95-280 "existing PSA methods and knowledge are expected to be sufficient for some applications; new methods will likely be needed for others." [3]

In evaluating RISI applications, the EPRI team concluded that a different approach may be warranted in order to establish the risk-importance of piping elements. Application of traditional risk importance measures may result in numerous problems, since it is very difficult to quantify effects of the inspection process on piping failure rates. Those problems are due to the difficulties listed below:

- uncertainties in inspection detection probabilities are high
- the ability to quantitatively characterize different pipe failure mechanisms is very limited
- low piping failure rates do not provide for good statistical significance

These difficulties are the reasons the EPRI team opted for a different approach in applying PSA models in the RISI process. The basis for the EPRI approach can be found directly in the definition of risk-based regulations, defined as a regulatory approach in which operating experience and engineering judgment are used together with the analytical insights derived from a PSA. [33] In order to deal with PSA limitations when applied to the RISI process, the approach developed by the EPRI team blends PSA insights with engineering analysis, operating experiences, and traditional deterministic approaches.

The PSA insights in EPRI RISI methodology are based on the logic structure used in the PSA: the event trees, system models, and the critical failure combinations (minimal cutsets). The critical failure combinations and the acceptable success paths are analyzed

for each safety function in order to determine the level of plant protection and importance of different mitigating functions. The use of PSA insights, and how they are applied in consequence evaluations, will be explained in more detail in Section 3.

The traditional deterministic approaches are included in EPRI RISI methodology through qualitative risk consideration of design basis accidents, requirements for safety train redundancy, and protection against single failures. Those traditional approaches have always contained implied elements of probability, and can be supported by the numerical values from PSA probabilistic evaluations.

Operating experience is very important in evaluating pipe failure probabilities and the connection between pipe failures and the presence of different degradation mechanisms. Since service experience has demonstrated that the likelihood of a piping failure is strongly dependent upon presence of an active degradation mechanisms, this approach provides the utility engineer a systematic way to determine the relative probability of pipe rupture by identifying and evaluating the type of degradation mechanism present in a pipe segment. These issues are discussed in Section 4.

All aspects are connected together in one organized engineering analysis. The steps and tools for that analysis, necessary information, and documentation are described in this report.

2.2 Overview of the EPRI RISI Process

The basic objectives of the RISI evaluation process are to identify risk-significant pipe segments, define the locations that are to be inspected within these segments, and identify appropriate inspection methods. The approach described here is expected to:

- Provide a simplified, yet robust, methodology which satisfies all intents of the risk-informed processes
- Reduce the documentation and quality assurance burden
- Promote consistent application by utility personnel
- Reduce the influence of uncertainties in PSA models
- Reduce the influence of PSA model assumptions
- Reduce the influence of uncertainties associated with pipe failure probability calculations
- Provide a documented and reviewable evaluation in accordance with utilities' quality assurance programs

The evaluation process includes:

- Selection of systems and defintion of boundaries for evaluation
- Failure Modes and Effects Analysis (FMEA)
- Risk Evaluation
- Determination of Inspection Requirements
- Examination Methods, Volume, and Acceptance Criteria

This is a new approach to nuclear risk-informed applications, but similar approaches are receiving increased attention in different industries in the United States and abroad. The evaluation process is illustrated in Figure 2.1.

2.2.1 System Selection and Evaluation Boundaries

The EPRI RISI methodology has been developed so that it can be applied irrespective of the scope of piping under evaluation. The methodology is technically correct and fundamentally robust regardless of whether a system or group of systems (e.g., the entire plant) is evaluated. Issues, such as ASME code piping currently exempted from volumetric examinations, non ASME code class piping, etc., although potentially important from an integrity management perspective are not germane to this methodology. It is expected that a better understanding of scope related issues will be gained through the completion of ongoing risk informed inspection pilot application studies.

The EPRI pilot application studies currently underway are being conducted consistent with the guidance provided by the draft ASME code case on RISI [16] and the NEI risk-based inspection guideline. [4] As part of this effort, each plant is reviewing the scope of piping included in the RISI evaluation boundaries. As appropriate, exempt and non-code piping is being evaluated to assess its risk significance and develop a determination as to its disposition from an integrity managment perspective.

2.2.2 Failure Modes and Effects Analysis

The FMEA consists of a consequence evaluation and failure modes evaluation. In the consequence evaluation, impacts of the postulated pipe failure are evaluated, as discussed in Section 3. In the failure mode evaluation, different piping degradation mechanisms are evaluated, as discussed in Section 4. The result of the FMEA is an identification of the pipe segments with common consequences and degradation mechanisms.

2.2.3 Risk Evaluation

Risk evaluation, described in Section 5 consists of categorization of consequences and failure potential and combinations into one of seven risk categories. PSA qualitative insights are used in determining consequence categories, as described in Section 3.2. Failure potential categories are not based on numerical estimates, but rather, are determined by identifying the type of degradation mechanism present in the pipe segment as described in Section 4.3. In order to account for uncertainties the risk categories are grouped into one of three risk regions: High, Medium, or Low.

2.2.4 Inspection Requirements

Inspection Requirements are determined in the last step of the analysis. The potential locations to be examined (elements) are selected from the risk-significant segments. The number of elements examined as part of the RISI program is based on the risk category for the risk-significant segments and will be a percentage of the total number of elements in each risk regions, as described in Section 6.

Selection of examination methods is described in Section 7. The selection of specific elements for examination within a segment is based on the degradation mechanism, as well as inspection cost, radiation exposure, and accessibility.

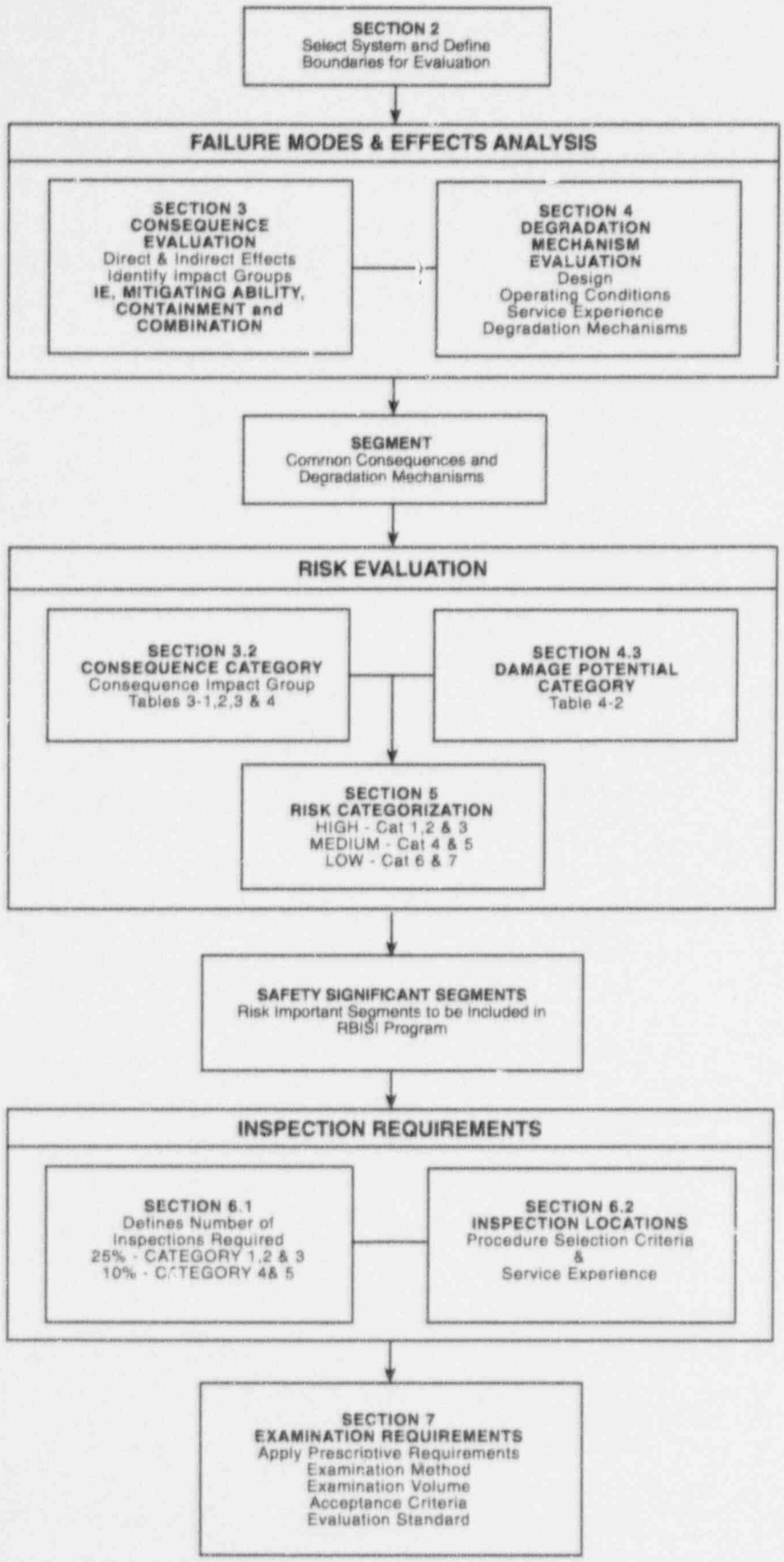


Figure 2-1
Overview of the RISI Evaluation Process

3

CONSEQUENCE EVALUATION

3.1 Basic Factors

The Consequence Evaluation focuses on the impact of a pipe segment failure (loss of pressure boundary integrity) on plant operation. This impact can be direct or indirect:

> **Direct**: Failure results in a diversion of flow and a loss of the train/system or an initiating event (such as a LOCA).
>
> **Indirect**: Failure results in depletion of a tank and a loss of the systems supplied from the tank, or results in a flood or spray, spatially affecting neighboring equipment.

Spatial effects are an example of an indirect effect of the pressure boundary failure. These include the effects of flood, spray, and pipe whip on equipment located in the vicinity of the break. Spatial consequences of the break are determined based on the position of the analyzed break and the relative location of important equipment. Selection of the location should be consistent with locations selected in other spatial analyses performed for the plant (e.g., internal flood analysis or fire analysis). The presence of important equipment in a specific location should already have been identified through those analyses and can be confirmed by a walkdown.

The possibility of isolating a break is also identified in the consequence analysis. A break could be automatically isolated by a protective check valve, a closed isolation valve, or an isolation valve that closes on a given signal. If not automatically isolated, a break can be isolated by an operator action, given a successful diagnosis. Isolability of the break depends on the availability of isolation equipment, the means of detecting the break, and the length of time available to prevent specific consequences (e.g., flooding of the room or draining of the tank).

Consequences are analyzed assuming the worst-case break, which is a large break. Large breaks are assumed to result in a diversion of flow in any size pipe. Small leaks often do not need to be explicitly considered in the analysis because, in most of the systems, they do not result in a significant consequence. Of course, those systems where a small leak can cause a measurable consequence need to be identified.

In the Consequence Evaluation, the pipe runs, where failure results in the same consequences, are identified. Those pipe runs are then broken down into pipe segments, based on the rules described in Section 5.1.

3.2 Consequence Ranking and Categorization

In order to rank consequences, a simplified basic qualitative model of risk associated with nuclear power plant design and operation is used. A similar model is discussed in Reference 6. In this model, risk is represented as follows:

$$\textbf{Risk} = \mathbf{P_i * P_m * P_c}$$

where,

- $\mathbf{P_i}$ represents the probability of an initiating event, such as loss of feedwater or loss of coolant accident
- $\mathbf{P_m}$ represents the probability of not being able to mitigate the undesirable propagation of an event. Core damage prevention is used as a measure of successful mitigation.
- $\mathbf{P_c}$ represents the probability of not being able to mitigate the consequences of the event using containment integrity preservation as a measure of success.

In Reference 6, P_i, P_m and P_c were defined as "risk management factors" and can be thought of as impact groups. They can be mathematically quantified, but it is not necessary to do so to gain insights into design vulnerabilities or operational risk. Those insights can be developed through qualitative risk analysis techniques, as will be shown in this chapter.

Failure of a pipe segment can be placed into one of the following impact groups:

Impact Group	Pipe Failure Consequence
Initiating Event	Initiating Event
Mitigating Ability	Loss of System or Multiple Systems Degradation of a System or Multiple Systems Loss of Train or Multiple Trains Degradation of a Train or Multiple Trains
Containment	Loss of Containment Integrity Degradation of Containment Integrity
Combination	Any Combination of Pipe Failure Consequences

For the last impact group above, a pipe failure can result in any combination of consequences from the previous groups. For example, an initiating event could occur in combination with the loss of a system or train, or a loss of multiple systems can occur in combination with degradation of containment integrity. The consequences listed above could occur as the result of either a direct or indirect effect of pipe failure.

The goal in the consequence evaluation is to establish a process which consistently ranks consequences caused by a pipe failure, based on their safety impact or risk significance. Is a pipe break resulting in a loss of coolant accident more safety significant than a pipe break leading to a loss of feedwater? Or, is a pipe break disabling one train of high pressure injections more safety significant than a pipe break disabling an auxiliary feedwater train? In order to answer these questions consistently, consequences are categorized in different importance groups or categories.

In this analysis, four consequence categories are used: HIGH, MEDIUM, LOW, and NONE. The "High" category represents events with a significant impact on plant safety, while the "Low" category represents events with a minor impact on plant safety.

Consequences are categorized in different importance categories, by applying a qualitative approach, as discussed in Section 2. A qualitative approach to the consequence categorization is based on the logic structure of the PSA. The logic structures specifically examined in this process include event tree and system models, critical failure combinations (minimal cutsets), and acceptable success paths.

The critical failure combinations and the acceptable success paths are analyzed for each safety function in order to determine the level of plant protection and importance of different mitigating functions.

The basic consequence ranking philosophy, used in this analysis, can be summarized as:

> **High Consequence:** Pressure boundary failures resulting in events which are important contributors to the plant risk or pressure boundary failures which significantly degrade the plant's mitigating ability.
>
> **Low Consequence**: Pressure boundary failures resulting in anticipated operational events or pressure boundary failures which do not significantly impact the plant's mitigating ability.
>
> **Medium Consequence**: is included to accommodate failure events which do not obviously belong to the "High" or "Low" rank.

In the next four sections, assignment of pipe failures to different impact groups will be discussed in detail. It should be noted that, regardless of the impact group, the assignment of each corresponding category is depends on the plant's sensitivity to different design basis events. As such, each consequence should be treated on a plant-specific basis.

3.2.1 Initiating Event Impact Group

In this part of the consequence analysis, the potential for pressure boundary failure to result in an initiating event or forced plant shutdown is evaluated. This should be accomplished using a plant-specific list of initiating events from the plant PSA/IPE and design basis documentation, including events that might not be explicitly modeled by either process.

An initiating event could occur as a result of a loss of fluid (e.g., LOCA, steam or feedwater line break, etc.), or as a result of the loss of a system. (e.g., loss of charging, loss of component cooling, etc.).

In this analysis, the importance of different initiating events, caused by pipe failure, needs to be assessed in order to place them into their appropriate consequence categories. In order to rank impact of one initiating event versus another, the plant mitigating abilities need to be considered. The plant mitigating abilities are usually much higher for the events which are anticipated during a plant's life than for the events not expected to occur during the plant's life. Also, different plants are sensitive to different types of events, depending on their mitigating abilities.

The initiating event frequency due to failure of active components is also a factor which needs to be considered. The relative contribution of piping failure to the frequency of an anticipated initiating event is expected to be much lower than to the infrequent events or accidents.

Considering this, it is expected that a pipe failure resulting in an initiating event, which in the plant design basis documents is expected with a low frequency of occurrence and is a significant contributor to plant risk, should be categorized as "High". An example of this would be a pipe failure causing a LOCA in a typical PWR plant. A LOCA in a typical BWR plant is expected with the same low frequency of occurrence, but it is usually not an important contributor to plant risk, and, therefore, with this result a pipe can be categorized as "Medium."

Conversely, a pipe failure resulting in an initiating event, which in the plant design basis documents is expected with a high frequency of occurrence and is a minor contributor to plant risk, should be categorized as "Low." An example of this would be a pipe failure causing a normal transient like loss of charging in a typical PWR.

Those principles are illustrated in Table 3.1. In this table, based on the expected frequency of occurrence, initiating events are grouped into four design basis event categories. The first category, routine operation, is not relevant to this analysis. If a postulated pipe failure results in a Category IV event, or an event not expected to occur during the lifetime of a particular plant, the assigned consequence category should be "Medium" to "High," depending on plant-specific design features (primarily mitigation systems).

Conversely, if a postulated pipe failure results in a Category II event, anticipated operational occurrence, the significance of this impact is not expected to be high, and the assigned consequence category should be "Low."

Failures that result in Category III events, infrequent events, can vary between "High" and "Low" consequence categories, depending on the specific initiating event and importance of that event to plant risk. For example, loss of offsite power (LOSP) is expected to be a significant risk contributor, and, therefore, should be assigned to a "High" consequence category, while loss of primary flow is not expected to be a significant risk contributor and, therefore, should be assigned to a "Low" consequence category. (Note: pipe failure can result in LOSP due to spatial effects of the break, for example, flooding of the switchgear room.)

Each consequence category for pipe failures resulting in an initiating event is assigned a consequence category according to the Conditional Core Damage Probability (CCDP) for corresponding to that event in the plant PSA. The correlation used to assign these consequence categories is given below:

Consequence Category for Pipe Failure Resulting in An Initiating Event	**Corresponding CCDP Range**
"HIGH"	$CCDP > 10^{-4}$
"MEDIUM"	$10^{-6} < CCDP < 10^{-4}$
"LOW"	$CCDP < 10^{-6}$

Given the low pipe failure frequency, low CCDPs for "Medium" and "Low" categories guarantees that pipe segments whose failure consequences are not assigned to the "High" category have a negligible contribution to the total core damage frequency (CDF).

Table 3.1
Example of Guidelines for Assigning Consequence Categories to Pipe Failures Resulting in an Initiating Event

Design Basis				
Initiating Event Category	**Initiating Event Type**	**Expected Initiating Event Frequency (1/yr.)**	**Initiating Event Examples**	**Recommended Consequence Category**
I	Routine operation	>1	Startup, shutdown, standby, refueling, etc.	N/A
II	Anticipated operational occurrence	$\geq$1 (events that might occur during a calendar year in a particular plant)	Reactor trip, turbine trip, partial loss of MFW	Low
			Loss of primary flow	Low
III	Infrequent events	$10^{-1}/10^{-2}$ (events that might occur during the lifetime of a particular plant)	Excessive feedwater/steam removal	Medium
			LOSP	High
IV	Limiting faults or accidents	$<10^{-2}$ (events not expected to occur during the plant's lifetime)	SLOCA MLOCA/LLOCA SLB ISLOCA	Medium/High

3.2.2 Loss of Mitigating Ability Impact Group

In this part of the consequence analysis, the potential for pressure boundary failure to degrade plant mitigating ability is evaluated. The pipe failure can result in a loss or degradation of a system/train, or possibly, multiple systems/trains.

A system/train can be lost either due to diversion of flow or spatial or secondary effects of the failure. Both direct and indirect effects of pipe failure need to be evaluated to determine the affected systems. There will be times when failure of the pipe will not result in a loss of system/train, but in a partial degradation of the system/train. This possibility should also be identified here.

As part of this analysis, the means of detecting a failure and technical specifications associated with the analyzed system must also be evaluated. Possible automatic and operator actions to prevent or recover a loss of systems should also be evaluated.

The risk significance of a pipe segment failure that causes the loss of systems, or trains, and a combination of these, depends on the three attributes discussed below:

1. **Frequency of the challenge**, which determines how often the mitigating function of the systems/trains is called upon. (This corresponds to the frequency of initiating events that require the systems/trains operation.)

2. **Number of backup systems/trains available**, which determines how many unaffected systems or trains are available to perform the same mitigating function. The availability of multiple backup trains could make the effect of the loss of systems/trains less significant. Backup systems should be evaluated for each plant safety function (reactivity control, secondary heat removal, RCS inventory, etc.)
3. **Exposure time**, which determines the downtime for the failed systems/trains, or the time the systems/trains would be unavailable before the plant is shutdown. Exposure time is a function of the test interval, the detection time, and allowed outage time (AOT). AOTs are plant-specific and, usually, short for important safety components. The key attributes in determining the exposure time are the system states when the pipe failure is expected to occur (standby, test, or real demand), and time required for the break detection (means available to detect diversion of the flow).

Table 3.2 provides an example for assigning consequence categories to pipe failures, which causes the loss of a system or train and, therefore, affects the mitigating ability of the plant. As for the initiating event evaluation, the frequency of challenge is grouped into design basis event categories (I, II, III, and IV): anticipated events, infrequent events and accidents.

Table 3.2
Example of Guidelines for Assigning Consequence Categories to Pipe Failures Resulting in System/Train Loss

Affected Systems		Number of Unaffected Backup Trains			
Frequency of Challenge	Exposure Time to Challenge	0	1	2	≥ 3
Anticipated (DB Cat II)	All year	H	H	M	L
	Between tests (1-3 month)	H	H	M	L
	Long AOT (1-2 week)	H	M	L	L
	Short AOT (≤ 3 day)	H	M	L	L
Infrequent (DB Cat III)	All year	H	H	M	L
	Between tests (1-3 month)	H	M	L	L
	Long AOT (1-2 week)	H	M	L	L
	Short AOT (≤ 3 day)	H	L	L	L
Unexpected (DB Cat IV)	All year	H	M	L	L
	Between tests (1-3 month)	H	M	L	L
	Long AOT (1-2 week)	H	L	L	L
	Short AOT (≤ 3 day)	H	L	L	L

H ≡ High Consequence Category

M ≡ Medium Consequence Category

L ≡ Low Consequence Category

Four different exposure times are considered:

1. **All Year**, which applies to standby systems and parts of systems where pipe segments are not "tested" or are exposed to the load during a year;
2. **Time Between Tests**, applies to the standby systems, which are regularly tested (monthly or quarterly). It is assumed that for those systems an actual exposure time is equal to the test interval (1 month/3 months), because, if a pipe degraded condition is present, it will be discovered during the test.
3. **Long AOT**, applies to operating or standby systems where pipe failure will be detected within a short time after the occurrence, and the plant will shutdown if the failure is not recovered during the AOT. The exposure time is, therefore, equal to the AOT plus detection time. A "long AOT" exposure time is one to two weeks.
4. **Short AOT**, applies to the same systems as the "long AOT," but the exposure time is less than 72 hours.

The number of backup trains refers to the number of unaffected trains available to perform the same safety function. If the affected systems/trains are needed to mitigate different safety functions, then the number of backup systems available should correspond to the lowest number from the various functions

Two cases will be discussed as an example. In Case 1, a pipe failure will disable Emergency Feedwater Train A. This Train is regularly tested. The emergency feedwater is required to mitigate anticipated events (DB Category II); exposure time is 3 months, and more than 3 backup trains are available (main and auxiliary feedwater, other train of emergency feedwater and feed and bleed). By using Table 3.2, data from this case will result in a "Low" consequence category. In the plant where main feedwater and feed and bleed are not credited in the PSA, 2 backup trains will result in a "Medium" consequence category.

In Case 2, a pipe failure will disable a High Pressure Safety Injection System (HPSI). Failure occurs in the pipe segment not regularly tested. HPSI is required to mitigate LOCAs or accidents (DB Category IV), exposure time is all year, and only one mitigating train is available (depressurization, and use of low pressure injection systems). By using Table 3.2, data in this case will result in a "Medium" consequence category.

The consequence categories in Table 3.2 are intended to be generic and will be validated as part of the ongoing EPRI BWR and PWR pilot application studies. Each consequence category will be confirmed by a numerical evaluation. Conditional core damage probabilities corresponding to the given system/train failure will be used to assign consequence categories according to the correlation given below:

Consequence Category for Pipe Failure Resulting in A Loss of System/Train	Corresponding CCDP Range
"HIGH"	$CCDP > 10^{-4}$
"MEDIUM"	$10^{-6} \leq CCDP \leq 10^{-4}$
"LOW"	$CCDP < 10^{-6}$

Given the low pipe failure frequency, the low CCDP for the "Medium" and "Low" categories guarantees that pipe segments whose failure consequences are not assigned to the "High" category have a negligible contribution to the core damage frequency.

3.2.3 Containment Performance Impact Group

In this part of the consequence analysis, the potential for pressure boundary failure to degrade containment performance is evaluated. It is not likely that a pipe failure can result in a direct containment bypass, but it can significantly affect containment isolation ability. Table 3.3 provides an example for assigning consequence categories to pipe failures, which causes degradation in containment isolation and increases the potential for an unisolated LOCA, outside of the containment. Table 3.3 is also plant specific, and sensitive to the location where the pipe break has occurred, and to the information available about passive barriers (check valve leak information, etc.)

3.2.4 Combinations Impact Group

Example guidelines to determine the consequence categories for the combination consequence group are given in Table 3.4, for pipe failures which cause both an initiating event and affect mitigating ability. As shown in the table, if a postulated pipe segment failure results in an initiating event and a loss of the system which is not needed to mitigate this initiating event, then it is recommended that this combination be treated as a single initiating event, where Table 3.1 applies. In other cases, if the category recommended in Table 3.4 is lower than one recommended in Table 3.1, the worst case category should be used.

Other combinations can be treated similarly. Those of special interest include combinations of degradation of containment barriers with a significant decrease in mitigating ability. It would be expected, that the pipe failure affecting more than one impact group will put the plant in a state of heightened risk.

Table 3.3
Example of Guidelines for Assigning Consequence Categories to Pipe Failures Resulting in Increased Potential for an Unisolated LOCA Outside of Containment

Remaining Protection Against Containment Bypass	Consequence Category
1 Active[1]	HIGH
1 Passive[2]	HIGH
2 Active	MEDIUM
1 Active, 1 Passive	LOW
2 Passive	LOW
More than 2	NONE
Note 1 - An Active Protection is presented by a valve which needs to close on demand Note 2 - A Passive Protection is presented by a valve which needs to remain closed.	

Table 3.4
Example of Guidelines for Assigning Consequence Categories to Combinations of Consequence Impacts

Combination Event	Consequence Category
Initiating Event and Mitigating Ability Affected (one unaffected train available for mitigation)	HIGH
Initiating Event and Mitigating Ability Affected (two unaffected trains available for mitigation)	MEDIUM (or IE category from Table 3.1, if higher)
Initiating Event and Mitigating Ability Affected (more than two unaffected trains available for mitigation)	LOW (or IE category from Table 3. 1, if higher)
Initiating Event and <u>no</u> Mitigating Ability Affected	IE consequence category from Table 3.1
Note 1 - Mitigating systems always correspond to the analyzed limiting event.	

4

DEGRADATION MECHANISM EVALUATION

4.1 Piping Failure Potential Assessment

In addition to pipe failure consequence, application of a risk-informed ISI selection process requires that the piping failure potential also be evaluated. The task of estimating piping failure probabilities can be a difficult and costly aspect of a risk-based evaluation. In addition, significant uncertainties are associated with any computational estimate employed. The challenge posed to EPRI was to establish a practical cost effective approach that could be used by plant personnel to account for failure potential. Four methods were considered. These methods included: *Expert Judgment, Structural Reliability Analysis, Service Based Failure Rates*, and *Degradation Mechanism Evaluation*.

4.1.1 Expert Judgment

This approach relies on the elicitation of expert opinion in order to assign numerical estimates for catastrophic or disruptive failures for selected pressure boundary systems and components. It generally calls for the establishment and training of a panel of experts. This panel should have a large base of experience with structural integrity issues at operating nuclear power plants as well as an understanding of the response of structural materials to various service environments. In early risk-based inspection pilot studies at Surry [15] expert judgment was selected as the method for estimating failure probabilities and experts were enlisted from reactor vendors, utilities, federal government, national laboratories, and academia.

Although effectively used in early pilot studies, implementation of this method is not practical for most plants. The process is very cumbersome and costly when used on a large scale. Operating plants generally have limited expertise in these areas and will therefore be forced to rely heavily on outside consultants. Previous studies also have shown that significant variations can exist in these predictions. In the absence of any prescriptive guidance, it will be difficult to establish some level of consistency in these predictions when applied at different plants.

4.1.2 Structural Reliability Analysis (SRA)

SRA employs the use of probabilistic fracture mechanics techniques to calculate the failure probability as a function of time, including the effects of inspection frequency and probability of detection (POD). Through the application of Monte Carlo sampling, the results from a very large number of crack simulations can be tracked and used to determine the fraction of cracks that will not be detected and repaired before failure.

The occasions in which plant engineers need to employ probabilistic fracture mechanics to resolve operating plant issues is extremely rare. Since these analyses are generally not used, most utilities do not maintain the expertise nor engineering tools to perform these calculations. These models are computationally intensive and the analyst must make assumptions regarding crack size distributions in the material, assumed stress history (cyclic stresses, mean stresses, number of stress cycles, etc.), and POD. In the absence of an adequate data base to draw upon and industry consensus regarding acceptable values to use, these assumptions are subject to much uncertainty.

Secondly, the Section XI inservice inspection program and supporting calculations are subject to the applicable requirements of 10CFR50 Appendix B. Therefore, these models must be verified and validated and the calculations must be independently reviewed. This can be difficult and extremely expensive.

Finally, these models depend heavily on cyclic design stress history and future cyclic loading predictions in order to support the necessary fatigue crack growth calculations. For most plant systems, especially ASME Class 2 & 3 and ANSI B31.1 designed piping, this information is not readily available. Also, service experience [20] has shown no correlation between actual failure probability and design stresses in Design Reports.

4.1.3 Service-Based Failure Rates

A service based failure rate method [13], currently underdevelopment at EPRI, would compute pipe break frequency for a given degradation state. This method is based on work by Thomas [18] with modifications similar to those suggested by Gamble and Tagart [19]. In this method, pipe break frequency has the form:

$$\mathbf{P_s = S_o \cdot MA \cdot 1\,0^{8}}$$

where:

$\mathbf{S_o}$ is a non dimensional scale factor that is a function of pipe geometry, number of welds, age and ratio of pipe rupture to leak events, and

MA is a degradation mechanism factor that accounts for the relative contribution to piping break frequency of individual degradation mechanisms present in the piping segment.

This method is attractive, since it focuses on the piping design configuration and the active degradation mechanisms present during operation. However, EPRI is still in the process of developing an adequate service experience data base that may be used to establish sufficient statistical basis for the above factors.

4.1.4 Degradation Mechanism Evaluation

Service experience [20] has shown no correlation between actual failure probability and design stresses in the Design Report. Failures typically result from degradation mechanisms and loading conditions (i.e. IGSCC, flow accelerated corrosion, thermal stratification, etc.) not anticipated in the original design. Since the likelihood of a piping failure is strongly dependent upon presence of an active degradation mechanism, the relative probability of pipe rupture could therefore be determined by identifying and evaluating the type of degradation mechanism present in a pipe segment. In this approach, the degradation mechanisms in a pipe segment are identified by comparing actual piping design and operating conditions to a well defined set of material and environmental attributes.

This approach was selected because:

1. The degradation mechanism attributes can be identified generically and consistently applied on a plant and pipe segment basis.
2. Utilities are familiar with this type approach since it has been used previously for various plant specific licensing evaluations.
3. This approach can be implemented by utility engineers and applied in a consistent fashion.
4. Sufficient service data is available to rank degradation mechanisms relative to their potential to produce a large pipe break.
5. The identification of degradation mechanisms is a precursor for the effective application of various computational models discussed previously.

4.2 Degradation Mechanism Descriptions and Attributes.

The purpose of this evaluation is to identify degradation mechanisms that can be present in piping within the selected system boundaries. In this process, the following design, fabrication, operational conditions, and service experience should be considered.

Design Characteristics: Design conditions include material selection, pipe size and schedule, component type (fitting type, ANSI standard, etc.), and other attributes unique to the system layout. It should be taken into account that design conditions vary between systems and can occasionally vary within a system.

Fabrication Practices: Fabrication practices might include material selection, weld wire, heat treatment, etc. It is expected that piping elements subjected to nuclear standards will not be exposed to damage mechanisms due to fabrication practices. However, past experience has shown that even nuclear standards have not prevented damage from phenomena unknown at the time of installation.

Operating Conditions: Operating conditions determine the piping elements' internal and external conditions that impact material degradation. These include operating temperatures and pressures, fluid conditions (stagnant, laminar, turbulent flow), fluid quality (primary water, raw water, dry steam, etc.), chemical control, and service environment (humidity, radiation, etc.).

Service Experience: Service experience provides confirmation that damage mechanisms identified for a specific location are appropriate and complete.

Many of the degradation mechanisms active in nuclear plants are present as a result of the combination of environment, service conditions, and operating requirements. As such, their presence cannot be avoided, and plant operators must therefore implement the appropriate measures to manage these degradation mechanisms.

The majority of piping system degradation results from growth-type degradation mechanisms. In these cases, a defect first initiates and then, over time, grows to the point of failure. Unless there is some abnormal loading, failure results in a leak. These mechanisms lend themselves well to the periodic inservice volumetric examinations as a means of managing the structural integrity of the component. A summary of these degradation mechanisms, which are considered in this evaluation, and their attributes and susceptible locations are provided in Table 4.1.

Table 4.1
Degradation Mechanisms

Degradation Mechanism	Criteria	Susceptible Regions
Thermal fatigue		
(a) Thermal stratification, cycling, stripping (TASCS)	(a) Areas where hot and cold fluid can mix where: Operating temp > 220°F(CS) or 270°F(SS), NPS >1 inch Vertical rise <45°F, and ΔT> 50°F or Richardson number > 4.0	(a) Nozzles, branch pipe connections, safe ends, welds, heat-affected zones (HAZ), base metal, regions of stress concentration
(b) Thermal transient	(b) Operating temp > 220°F(CS) or 200°F(SS), and ΔT> 150°F(CS) or 200°F(SS). and ΔT > T allowable	(b) Nozzles, branch pipe connections, safe ends, welds, HAZ, base metal, regions of stress concentration
Corrosion cracking		
(a) Chloride cracking	(a) Areas exposed to chloride contamination where temperatures >150°F and tensile stresses	(a) Base metal, welds and HAZ
(b) Crevice corrosion cracking	(b) Areas that contain crevices that can result in oxygen depletion and concentration of impurities	(b) Base metal, welds and HAZ
Primary water stress corrosion cracking	· Mill annealed Alloy 600 · Cold worked or cold worked and welded · Exposed to primary water temperature greater than 620°F	Nozzles, welds, HAZ without stress relief, thermowells

Table 4.1 (cont.)
Degradation Mechanisms

Degradation Mechanism	Criteria	Susceptible Regions
Intergranular stress corrosion cracking (IGSCC) (a) IGSCC - BWRs (b) IGSCC - PWRs	 (a) Generic Letter 88-01 (b) High oxygen, stagnant flow	 (a) Austenitic steel welds and HAZ (b) Austenitic steel welds and HAZ
Microbiologically influenced corrosion (MIC)	· Presence or intrusion of organic material · Untreated water · Low flow · Operating temperatures of 20 to 120°F · pH <10	Fittings, welds, HAZ, and base metal, especially regions containing crevices
Erosion-cavitation	· $(p_d - p_v)/\Delta p < 5$, and V > 30ft/sec. and fluid temperature < 250°F · EPRI TR-10318, T2, provides additional guidance	Fittings, welds, HAZ, and base metal
Flow-accelerated corrosion (FAC)	Evaluated in accordance with plant FAC program	Evaluated in accordance with plant FAC program

4.2.1 Thermal Fatigue

Mechanism Description: Alternating stresses caused by thermal cycling of a component results in accumulated fatigue usage and can lead to crack initiation and growth.

Attribute Criteria: Austenitic and carbon steel piping segments with operating temperatures less than 270 and 220°F, respectively, are not susceptible to degradation by thermal fatigue. Piping segments having operating temperatures greater than these values should be evaluated for the potential for degradation from thermal transients and thermal stratification, cycling, and striping as indicated in the following:

- **Thermal Transients**: Areas considered susceptible to thermal fatigue include pipe segments where there is relatively rapid cold water injection with DT greater than 150°F for carbon steel pipe and 200°F for austenitic steel pipe. When these temperature changes are exceeded, additional evaluations can be performed to determine if DT is greater than DT allowable. Procedures in EPRI report TR-104534, Vols. 1-4, "Fatigue Management Handbook" [21] can be used to determine DT allowable.

- **Thermal Stratification Cycling and Striping (TASCS)**: Areas where there can be leakage past valves separating hot and cold fluids and regions where there might be intermittent mixing of hot and cold fluids caused by fluid injection are considered to be susceptible to degradation from thermal fatigue, except for pipe segments where the pipe diameter is 1 inch or less, or the slope of the segment is 45° or more from the horizontal. When these criteria are exceeded, additional evaluations can be performed to determine if the maximum DT is greater than 50°F or the Richardson number is greater than 4.0. (Refer to EPRI report TR-104534, for procedures to compute the Richardson number.)

4.2.2 Corrosion Cracking

Mechanism Description: The electrochemical reaction caused by a corrosive or oxygenated media within a piping system can lead to cracking. This mechanism includes chloride and crevice corrosion.

Attribute Criteria:

- **Chloride Corrosion Cracking**: Austenitic steel piping and welds are considered susceptible to chloride corrosion cracking when exposed to chloride contamination (from insulation, brackish water, or concentration of fluids containing chlorides), temperatures greater than 150°F, and tensile stresses.
- **Crevice Corrosion Cracking**: Regions containing crevices (narrow gaps) that can result in a oxygen depletion and relatively high concentration of chloride ions or other impurities are considered susceptible to crevice corrosion cracking.

4.2.3 Primary Water Stress Corrosion Cracking (PWSCC)

Mechanism Description: PWSCC occurs when high-temperature primary water is the corrosive medium and is present in combination with a susceptible material and high tensile stress.

Attribute Criteria: Piping attachments (e.g., thermowells) are considered susceptible to PWSCC when they are fabricated from mill annealed Alloy 600 that is cold worked or cold worked and welded without subsequent stress relief, are exposed to primary water, and operate at temperatures in excess of 620°F. EPRI report TR-103696, "PWSCC of Alloy 600 Materials in PWR Primary System Penetrations",[22] provides additional detail for PWSCC degradation.

The attribute criteria specified for PWSCC in this section are applicable to PWRs. The susceptibility to corrosion cracking from PWSCC is covered for BWRs in the following section for IGSCC.

4.2.4 Intergranular Stress Corrosion Cracking (IGSCC)

Mechanism Description: IGSCC results from a combination of sensitized materials (caused by a depletion of chromium in regions adjacent to the grain boundaries in weld heat-effected zones), high stress (residual welding stresses), and a corrosive environment (high level of oxygen or other contaminants).

Attribute Criteria:

- BWRs: Piping within the scope of the RISI evaluation should be compared to piping included in the existing plant IGSCC inspection program developed in accordance with Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping". [23] Piping in the RISI evaluation scope should be identified as susceptible to IGSCC for the purpose of RISI evaluation if it is inspected as part of the existing plant IGSCC inspection program.
- PWRs: Welds and heat-affected zones in wrought austenitic steel PWR piping having high dissolved oxygen content and stagnant flow (e.g., stagnant, oxygenated borated water systems) are considered susceptible to degradation from IGSCC. Welds in materials considered to be resistant to sensitization from welding (see NUREG-0313, Rev. 2 [24]) are not susceptible to degradation from IGSCC.

4.2.5 Microbiologically Influenced Corrosion (MIC)

Mechanism Description: Microbes, primarily bacteria, have been found to cause widespread damage to low alloy and carbon steels. Similar damage has also been found at welds and heat-affected zones for austenitic stainless steels.

Attribute Criteria: Areas considered susceptible to degradation from MIC are piping components with fluids containing organic material or with organic material deposits. The most vulnerable components are raw water systems, storage tanks, and transport systems. Systems with low to intermittent flow conditions, temperatures between 20-120°F, and pH below 10 are primary candidates.

EPRI reports TR-103403, "Service Water System Corrosion and Deposition Source Book" [25]; NP-5580, "Sourcebook for Microbiologically Influenced Corrosion in Nuclear Power Plants" [26]; and NP-6815, "Detection and Control of Microbiologically Influenced Corrosion" [27], provide additional information regarding MIC degradation.

4.2.6 Erosion-Cavitation

Mechanism Description: This degradation mechanism represents degradation caused by turbulent flow conditions, which erode (wear away the metal) the pipe wall by cavitation. Cavitation damage is the result of the formation and instantaneous collapse of small voids within fluid subjected to rapid pressure and velocity changes as it passes through a region where the flow is restricted (e.g., a valve, pump, or orifice).

Attribute Criteria:

- Regions where $(p_d - p_v)/ \Delta p < 5$ psi, and $V > 30$ft./sec. and fluid temperature < 250°F are considered susceptible to degradation from erosion-cavitation, where p_d is the static pressure downstream of the unit (pump, valve, etc.), p_v is the vapor pressure, Δp is the pressure differential across the unit, and V is the flow mean velocity at the inlet of the unit. All pressures are gauge pressures.
- The susceptible region might extend a distance equal to approximately 5D downstream of a pump, flow orifice, throttling valve, pressure-reducing valve, or other potential sources of cavitation. (If an elbow is within 5D of the source of cavitation, then the affected region extends to the first weld past the elbow.)
- EPRI report TR-103198, A Method to Predict Cavitation and the Extent of Damage in Power Plant Piping, Vols. T1 and T2, [28] provide additional guidance for evaluation of erosion-cavitation susceptibility, including more detailed criteria for orifices, bends, and various types of values.
- Standard reducers do not create the potential for erosion degradation. Regions where flow occurs for less than 100 hrs/year are not considered to be susceptible to erosion-cavitation degradation.

4.2.7 Flow-Accelerated Corrosion (FAC)

Mechanism Description: FAC is a complex phenomenon that exhibits attributes of erosion and corrosion in combination. Factors that influence whether FAC is an issue are velocity, dissolved oxygen, pH, moisture content of steam, and material chromium content.

Attribute Criteria: Carbon steel piping with chromium content greater than 1% and austenitic steel piping are not susceptible to degradation from FAC. Piping within the scope of the RISI evaluation should be compared to piping included in the existing plant FAC inspection program. Piping in the RISI evaluation scope should be identified as susceptible to FAC for the purpose of RISI evaluation if it is inspected as part of the existing plant FAC inspection program.

EPRI report NSAC/202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program" [29], provides the general guidelines for the identification and inspection of components subject to FAC degradation.

4.2.8 Vibrational Fatigue

Mechanism Description: Vibration fatigue failures are normally a result of poor component design or fabrication practice. If the level of vibration is unacceptable (i.e., alternating stress levels are above the component's endurance limit), then failure occurs. In addition, the nature of this mechanism is such that, generally, almost the entire fatigue life of the component is expended during the initiation phase. Once a crack initiates, failure quickly follows. Consequently, this mechanism does not lend itself to typical periodic inservice examinations (i.e., volumetric, surface, etc.) as a means of managing this degradation mechanism.

Attribute Criteria: If a vibration problem is discovered, then corrective actions must be taken to either remove the vibration source or reduce the vibration levels to ensure future component operability. Therefore, frequent system walkdowns, leakage monitoring systems, and current ASME Section XI system leak test requirements are practical measures to address this issue. Because these measures are employed either singly or in combination for most plant systems, it is not necessary to use an RISI selection process for vibratory fatigue. During the performance of system walkdowns and leakage testing, operators should pay particular attention to small bore socket welded piping in the immediate vicinity of vibration sources such as pumps.

4.3 Degradation Mechanism Categories

Service data obtained from previous work [30, 31] were used to identify and assess the severity and frequency of degradation mechanisms that can be active in nuclear power plant piping. Approximately 1,000 cracking and leaking events and 100 rupture events (leak rates greater than 50 gpm) are identified in these reports.

Of the cracking and leaking events, no degradation mechanism was identified in the source material for 48% of the events, while 27% of the events were attributed to IGSCC, 4% were attributed to maintenance or installation errors, and 3% resulted from corrosion mechanisms other than IGSCC. The remaining identified degradation mechanisms each accounted for 1% or less of the total. Sufficient data was not provided to define the leak rates associated with individual events where there were leaks. These events are believed to have leak rates significantly less than 50 gpm, and were likely to have leak rates lower than the 1 and 5 gpm leak rate limits in the technical specifications for PWRs and BWRs, respectively.

Of the rupture events, 30% of the total were attributed to FAC, and 7% each to design and installation errors, maintenance errors, water hammer, and unknown mechanisms. The remaining mechanisms each were 1 to 4% of the total rupture events. Of the degradation mechanisms that are likely to be detected by periodic Section XI-type inspections, FAC is the only mechanism that has any significant potential for large leaks. Thermal fatigue and low cycle loading each accounted for 1% of the ruptures and are much less likely to produce large leaks. There were no large leak events identified for corrosion mechanisms; other than one event which was caused by external MIC on a buried pipe.

Based on the above data, degradation mechanisms are organized into the following three categories: ***Large Break, Small Leak, and None***. These categories are described in Table 4-2 below.

Table 4.2
Degradation Category

Large Pipe Break Potential	Leak Conditions	Degradation Category
High	>50 GPM	**"Large Break"** FAC
Medium	1-10 GPM	**"Small Leak"** Thermal Fatigue Corrosion Cracking, PWSCC, IGSCC, MIC, Erosion/Cavitation
Low	None	**"None"** No Degradation Mechanisms

The above categories illustrate the failure potential for given pipe segments. The expected likelihood that a pipe segment will experience a large break/rupture is highest for those segments exposed to damage mechanisms with the potential to cause large breaks. Similarly, the likelihood of a pipe rupture is lowest for those segments not exposed to any damage mechanisms.

Piping segments having the degradation mechanisms listed in the small leak category should be placed in the large leak category when the pipe segments also have the potential for water hammer loads. The potential for water hammer loads can be assessed using service experience, including any modifications made to reduce or eliminate the potential for water hammer.

For those cases where the segment consequence category, in Section 3 of this report, was based on a small leak rather than a large break, then the degradation category shall be assumed to be "Large Break" for all degradation mechanisms.

5

RISK EVALUATION

5.1 Segment Definition

Segments are determined by piping sections that:

- Are exposed to the same degradation mechanisms
- If failed, have the same consequences
- Are located in the same plant area
- Consist of a continuous run of piping

The segments failure probabilities are defined by degradation mechanism categories that define the relationship between leak size and degradation mechanism. The segment failure consequences are defined by consequence categories that define the relationship between the severity of consequences and the impact on plant safety and performance. The segment risk categories are formed by combinations of the degradation mechanism and consequence categories, as discussed below.

5.2 Risk Matrix

The risk of pipe segment failure is evaluated on the basis of the expected likelihood of the event and the expected importance of the consequence. The importance of the consequences is presented by the consequence categories. The likelihood of failure in this analysis is estimated based on the segment exposure to different degradation mechanisms and is represented by the degradation mechanism categories.

As is common in a qualitative risk-graded approach, the graphic method is used to illustrate the effects of these two parameters and to serve as a base for the selection of risk-important segments. The graphic structure used in this analysis, known as the risk matrix, is shown in Figure 5.1. Degradation mechanism categories shown in the figure are defined in Section 4.3. Consequence Categories shown in the figure are defined in Section 3.2. Figure 5.1 is used to define risk categories, which are identified on the risk matrix and described below.

Degradation Mechanism	Consequence Category			
	None	Low	Medium	Large
Large break	Risk category 7	Risk category 5	Risk category 3	Risk category 1
Small leak	Risk category 7	Risk category 6	Risk category 5	Risk category 2
None	Risk category 7	Risk category 7	Risk category 6	Risk category 4

High-risk regions

Medium-risk regions

Low-risk regions

Figure 5.1
Risk Matrix and Risk Categories.

5.3 Risk Categories

The three degradation mechanism categories and four consequence categories are combined into seven risk categories. Those categories are shown in Figure 5.1 and defined below:

Risk Category 1: **High** Consequences and **Large Break** Mechanisms

Risk Category 2: **High** Consequences and **Small Leak** Mechanisms

Risk Category 3: **Medium** Consequences and **Large Break** Mechanisms

Risk Category 4: **High** Consequences and **No** Degradation Mechanisms

Risk Category 5: **Medium** Consequences and **Small Leak** Mechanisms, or **Low** Consequences and **Large Break** Mechanisms

Risk Category 6: **Medium** Consequences and **No** Degradation Mechanisms, or **Low** Consequences and **Small Leak** Mechanisms

Risk Category 7: **Low** Consequences and **No** Degradation Mechanisms, or **No** Consequences and **Any** Degradation Mechanisms

The Risk Categories shown in Figure 5.1 are then further combined into these final ISI groups, or risk regions:

Corresponds to **high** risk, and includes risk categories 1, 2, and 3.

Corresponds to **medium** risk, and includes risk categories 4 and 5.

Corresponds to **low** (or negligible) risk, and includes risk categories 6 and 7.

In this risk-graded approach, the risk categories are combined into three risk regions for more robust and more efficient utilization. Three risk regions also account for uncertainties in the risk categorization, and ensure that 1) high consequence segments are considered for all likelihoods of failure, and 2) segments with the potential for large leaks (high likelihood of failure) are considered for all consequence categories (except "none").

6

INSPECTION LOCATION SELECTION

6.1 Risk-Informed Inspection Scope

The number of elements to be examined as part of the RISI program depends on the risk category for the risk-significant segments. An element is defined as a portion of the segment (e.g., nozzle, weld, etc.) where a potential degradation mechanism has been identified according to the criteria in Section 4. The following guidelines are to be used to determine the number of elements to be examined in each risk category.

- All elements, regardless of risk category, are to be subjected to pressure/leak testing requirements.
- Volumetric examinations are not required for those segments determined to be in Risk Category 6 or 7.
- For those segments that are in Risk Category 1, 3, or 5 and are included in the existing plant FAC (Generic Letter 89-08 [34]) inspection program, the number of inspection locations are to be the same as the existing plant FAC inspection program.
- For those segments that are in Risk Category 1, 2, 3, or 5 and are included in the existing plant IGSCC (Generic Letter 88-01 [23]) inspection program, the number of inspection locations are to be the same as the existing plant IGSCC inspection program.

For segments determined to have degradation mechanisms other than those included in the existing plant FAC and IGSCC inspection programs, the following number of locations are to be examined (beyond pressure/leak testing requirements) as part of the RISI program.

- For Risk Category 1, 2, or 3, the number of inspection locations in each category should be 25% of the total number of elements in each risk category (rounded up to the higher whole number). Selection of these elements is discussed in the next section.
- For Risk Category 4 or 5, the number of inspection locations in each category should be 10% of the total number of elements in each risk category (rounded up to the higher whole number). Selection of these elements is discussed in the next section.

These are minimum requirements. The utility should review the results of the element assessment evaluation to ensure that they satisfy individual, plant-specific piping integrity management objectives.

6.2 Selection of the Inspection Locations

The selection of individual inspection locations within a risk category depends on the degradation mechanism present, physical access constraints, radiation exposure, and cost considerations. An inspection-for-cause process shall be implemented at each inspection location. Therefore, examination methods, inspection volumes, and acceptance and evaluation criteria are to be designed specifically for the degradation mechanisms active at the inspection location. The following guidelines are to be used to define the inspection locations.

As with the selection of the number of inspection locations, elements that are in Risk Category 1, 3 or 5 and are included in the existing plant FAC inspection program, the inspection locations in each risk category are to be the same as those identified in the existing plant FAC inspection program.

As with the selection of the number of inspection locations, elements that are Risk Category 1, 2, 3, or 5 and are included in the existing plant IGSCC inspection program, the inspection locations in each risk category are to be the same as those identified in the existing plant IGSCC inspection program.

For those elements in Risk Category 1, 2, 3, or 5 determined to have degradation mechanisms other than those included in the existing plant FAC or IGSCC inspection programs and those elements in Risk Category 4, the inspection locations in each risk category are to be determined by considering the following:

- Access. There should be adequate access to the element to ensure the examination method defined in this section for the relevant damage mechanism can be used effectively for the defined examination volumes.
- Radiation Exposure. Elements should be selected to minimize personnel radiation exposure during inspection.
- Where applicable, relative degradation severity for specific degradation mechanisms is to be considered. For example, wear or erosion rates for erosion/corrosion, DT or Richardson number for thermal fatigue, NUREG-0313, Rev. 2 [24] weld categorization for IGSCC.
- Inspection locations for elements in Risk Category 4 segments should focus on any areas of significant stress concentration, geometric discontinuities, or terminal ends.
- Plant-specific inservice cracking experience.

7

MECHANISM SPECIFIC EXAMINATION VOLUMES AND METHODS

Application of RISI uses NDE techniques that are designed to be effective for specific degradation mechanisms and examination locations. The remainder of this section describes the examination volumes and methods that are appropriate for each degradation mechanism.

Table 7.1 provides a summary of the degradation mechanism-specific NDE methods, and the associated acceptance standards, evaluation standards, and inspection frequencies.

Table 7.1
Summary of Degradation-Specific Inspection Requirements and Examination Methods [1]

Degradation Mechanism	Degradation Mechanism Subcategory	Examination Requirement Fig. No.	Examination Method [2]	Acceptance Standard	Evaluation Standard
Thermal fatigue		7.1-1 7.1-2 7.1-3 7.1-4	Volumetric	IWB-3514	IWB-3640 or IWB-3650
Corrosion cracking	Chloride cracking (OD) Chloride cracking (ID) Crevice corrosion	Affected Surface 7.2-1 7.2-2 7.2-3	Surface Volumetric Volumetric	IWB-3514 IWB-3514 IWB-3514	IWB-3640 or IWB-3650
PWSCC		 7.3-1 7.3-2	Visual (VT-2) Volumetric	IWB-3142 IWB-3514	IWB-3640
IGSCC		7.4-1 through 7.4-5	Volumetric	IWB-3514	IWB-3640
MIC		7.5-1	Volumetric or Visual, VT3	IWB-5250(b) IWB-5250(b)	Code Case N-480 N-480 with volume equivalent thickness
Erosion-cavitation		See FAC	Volumetric	Same as FAC	Same as FAC
Flow-accelerated corrosion		7.7-1 through 7.7-7	Volumetric	Plant program	Plant program

[1] The frequency of inspection for each degradation category is each inspection interval, except for the existing plant inspection programs for IGSCC and FAC, where the frequencies specified in the plant programs are applicable.

[2] Volumetric examinations are generally performed using ultrasonics, unless otherwise indicated.

7.1 Thermal Fatigue

Affected Regions. Regions identified by TASCS or transient screening (see Section 4.2.1).

Examination Volumes: Volumes surrounding stress concentrations (e.g., counterbores, nozzle corners) and other high-stress regions (e.g., terminal ends). If there are no stress concentrations or high-stress regions, the application volume is volume around welds. Examination should focus on detection of cracks initiating and propagating from the inner surface.

Examination Volume Figures: See Figures 7.1-1, -2, -3, and -4. These volumes may need to be expanded, depending on the nature and extent of TASCS-type mechanisms.

Examination Methods: Volumetric. The following considerations are suggested for the examination of thermal fatigue cracks:

In contrast to mechanical fatigue, thermal fatigue cracking usually initiates as many small cracks and then one of the cracks becomes predominant. It has been most commonly observed at or near the pipe-to-nozzle weld where the wall thickness is thinner due to a counterbore or previous grinding on the inside surface. In feedwater piping, that predominant crack grows straight out in a radial-circumferential plane while the others remain small. The predominant crack tends to be located at the thinnest area and does not follow the weld fusion line.

- Examinations should be conducted from both sides of the weld even if additional surface preparation is necessary, unless prohibited by physical limitations.
- Scan at least 12 decibels (dB) over the standard ASME Code Section XI, Appendix III, gain.
- Obtain an accurate wall thickness profile.
- Look for excess inside-surface signals that are typical of thermal fatigue cracking, especially in thinner, more susceptible areas.
- The tip signal should always be lower in amplitude as compared to the corner trap signal.
- When sizing, consider the length of the indication; surface-connected cracks are almost always at least twice as long as they are deep, often 5 to 10 times as long.
- Determine whether the suspected tip signal actually plots to be exactly above the corner trap signal. For this purpose, a special reference block, with multiple parallel notches and holes above the notches, can be a useful training, reference, and qualification tool. It might be difficult to separate the signals manually, but a properly set up automated scan should be able to correctly identify the location of the signals

Focused transducers or the time-of-flight-diffraction (TOFD) technique are recommended for sizing and/or characterization. TOFD works especially well for finding the deepest crack in a group of cracks.

Acceptance Standard: Section XI, IWB 3514

Evaluation Standard (as applicable): Section XI, IWB - 3640 or IWB - 3650, as applicable

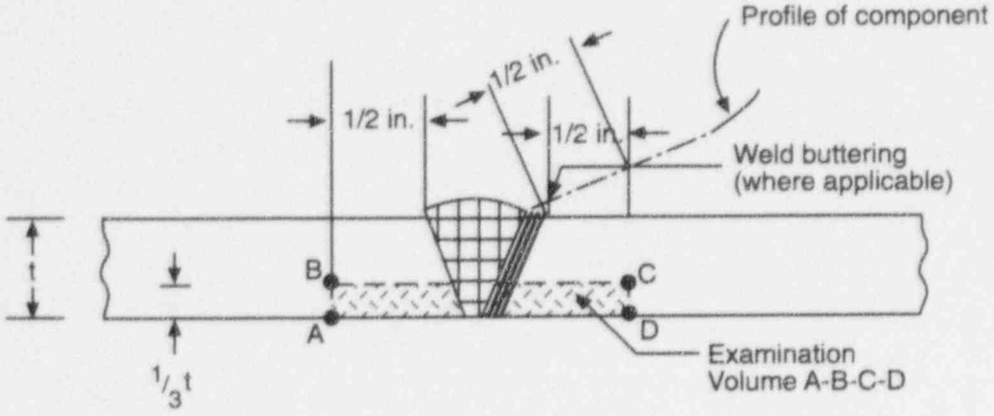


Figure 7.1-1
Examination Volume for Thermal Fatigue Cracking in Piping Welds less than NPS 4.

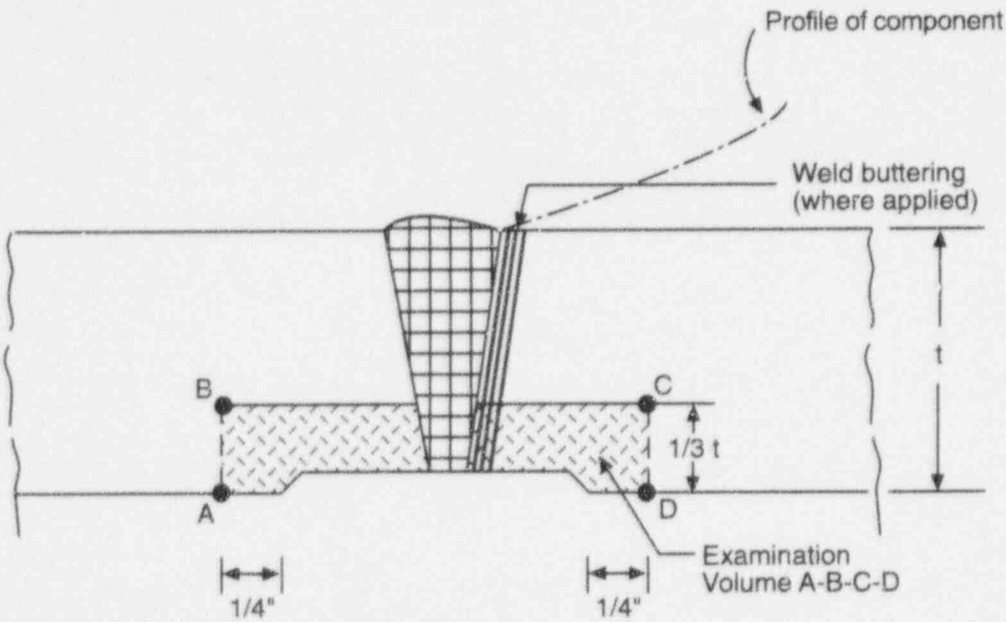


Figure 7.1-2
Examination Volume for Thermal Fatigue Cracking in Piping Welds NPS 4 or Larger.

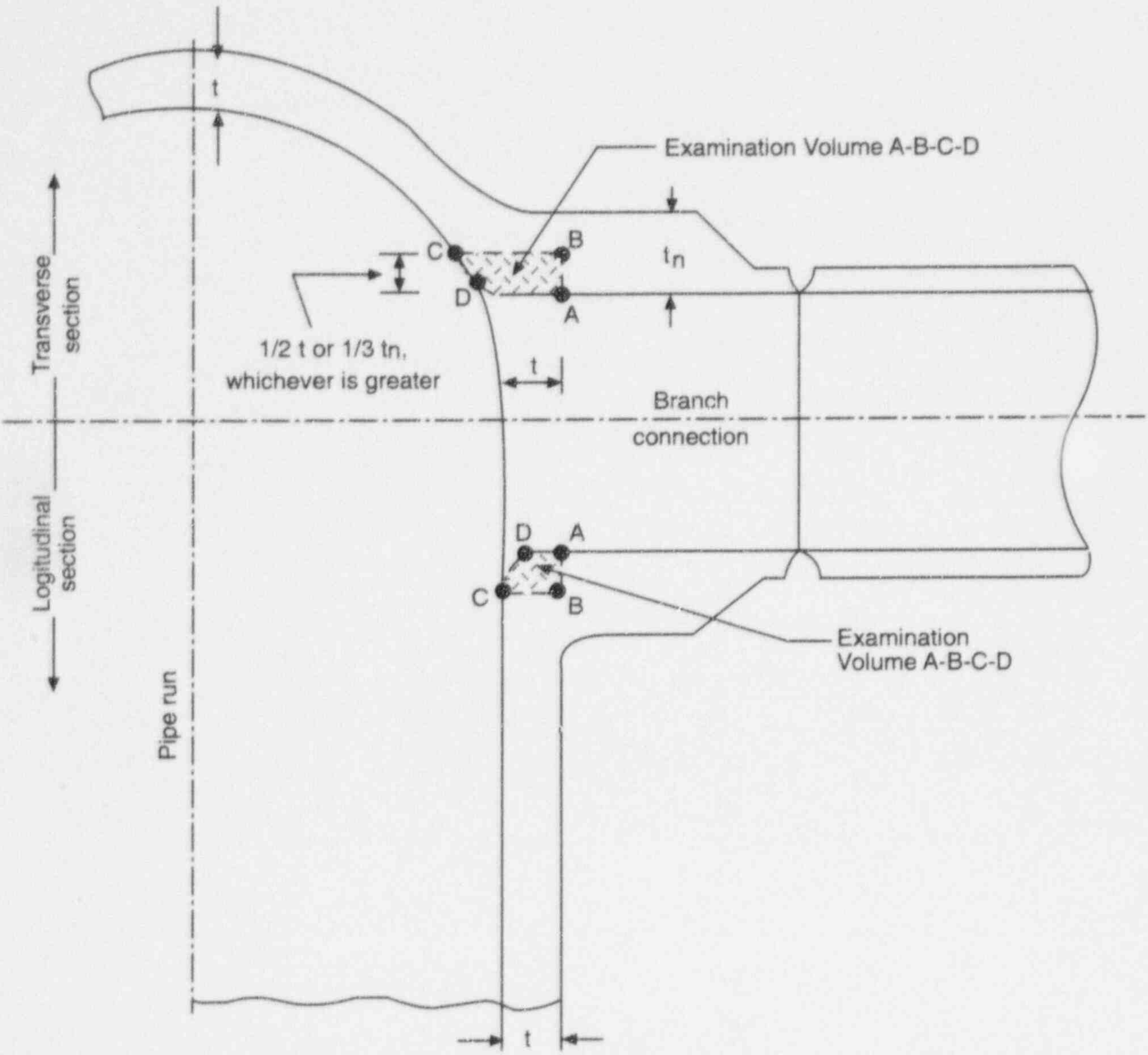


Figure 7.1-3
Examination Volume for Thermal Fatigue Cracking in Sweepolets.

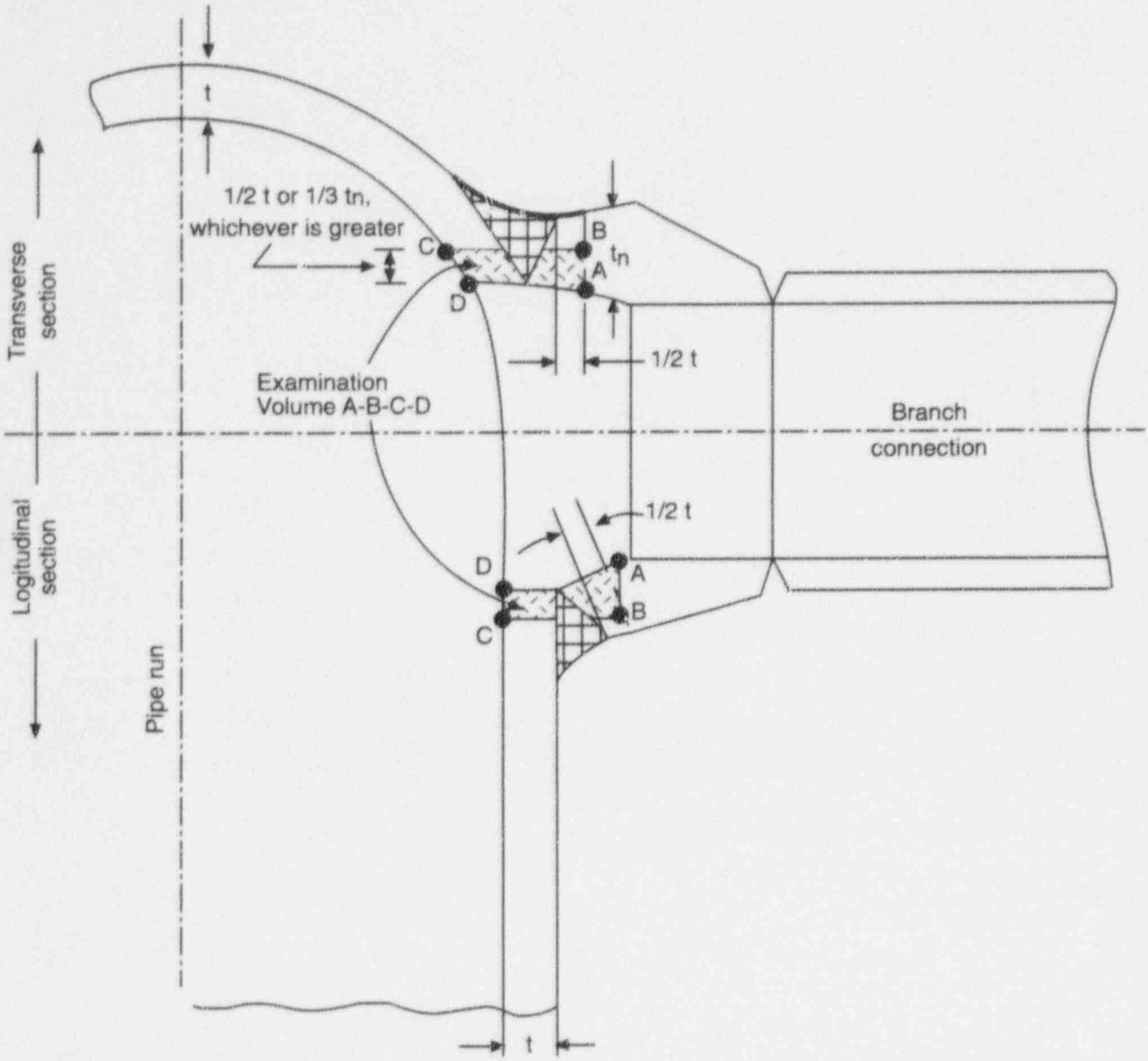


Figure 7.1-4
Examination Volume for Thermal Fatigue Cracking in Weldolets and Sockolets.

7.2 Corrosion Cracking

7.2.1 Chloride Corrosion Cracking

Affected Region: Austenitic steel piping and welds exposed to chloride contamination (from insulation, brackish water, or concentration of fluids containing chlorides), temperatures greater than 150°F, and tensile stresses.

Examination Volumes: Welds and weld heat-affected zones

Examination Volume Figures: See Figure 7.2-1.

Examination Method:

- Surface for cracking tha'. ›ight initiate at the pipe outside surface
- Volumetric for crackin, 'hat might initiate at the pipe inside surface

Acceptance Standard: Section XI, IWB-3514

Evaluation Standard (as applicable): Section XI, IWB - 3640

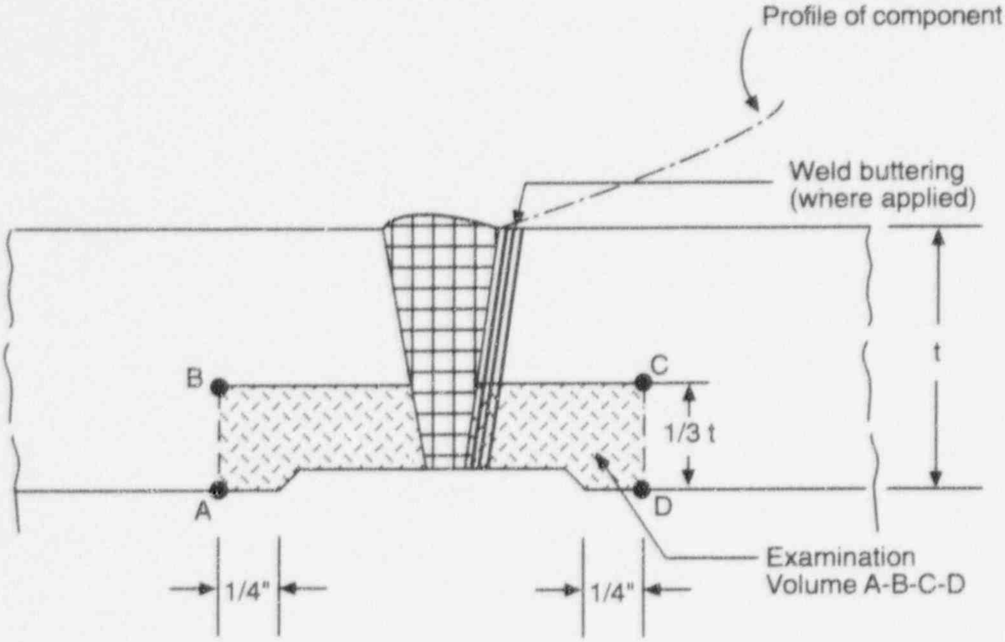


Figure 7.2-1
Examination Volume for Chloride Cracking in Pipe Welds.

7.2.2 Crevice Corrosion Cracking

Affected Region: Region where there are crevices (narrow gaps) that can deplete oxygen and concentrate chloride ions or other impurities, especially in welded attachments.

Examination Volumes: Volumes surrounding the weld, weld heat-affected zone, and base metal in the crevice region. Examination should focus on detection of cracks initiating and propagating from the inner surface.

Evaluation Volume Figures: See Figures 7.2-2 and -3.

Examination Method: Volumetric. Crevice corrosion cracking can be detected with NDE methods similar to those used for detection of IGSCC (see Section 7.4). Care must be taken to discriminate the crevice from cracking. Discrimination between cracks and crevices should be determined by comparing responses on a mockup.

Acceptance Standard: Section XI, IWB - 3514

Evaluation Standard (as applicable): Section XI, IWB - 3640 or IWB - 3650

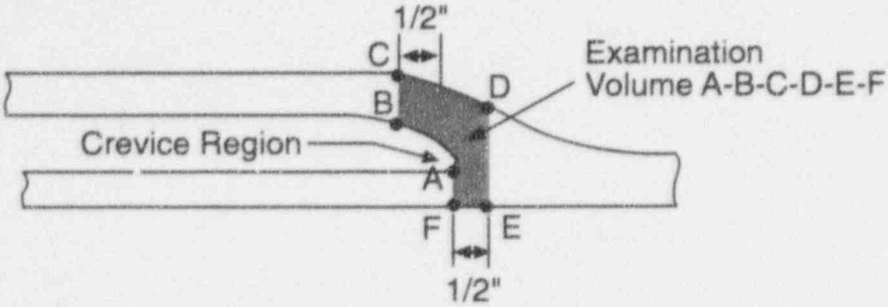


Figure 7.2-2
Examination Volume for Crevice Corrosion Cracking in Nonwelded Attachment.

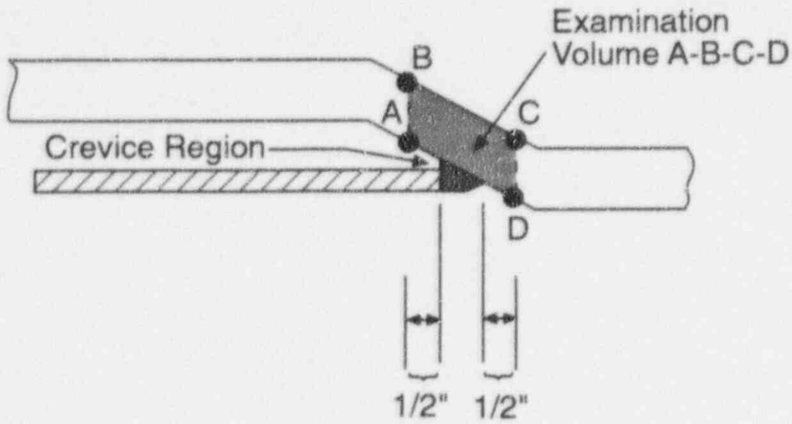


Figure 7.2-3
Examination Volume for Crevice Corrosion Cracking in Welded Attachment.

7.3 PWSCC

Affected Region: Mill annealed Alloy 600, including weld and weld heat-affected zones, in PWR primary system penetrations that have been cold worked or cold worked and welded, operate at temperatures greater than 620°F, and are exposed to primary coolant.

Examination Areas: Areas surrounding the weld, weld heat-affected zone, and base metal near the cold worked or cold worked and welded regions.

Examination Volume Figures: See Figure 7.3-1 and -2.

Examination Method: Visual examination of the outside surface for evidence of boric acid residue is typically used to detect through-wall PWSCC.

NDE techniques similar to the ultrasonic techniques used for detection of IGSCC, also may be used for detection of PWSCC. Eddy current techniques can be used when access to the inside surface of the piping is practical. It also is possible to use radiography for detection of this damage mechanism.

Acceptance Standard: Section XI, IWB - 3142 and IWB-3514

Evaluation Standard (as applicable): Section XI, IWB - 3640

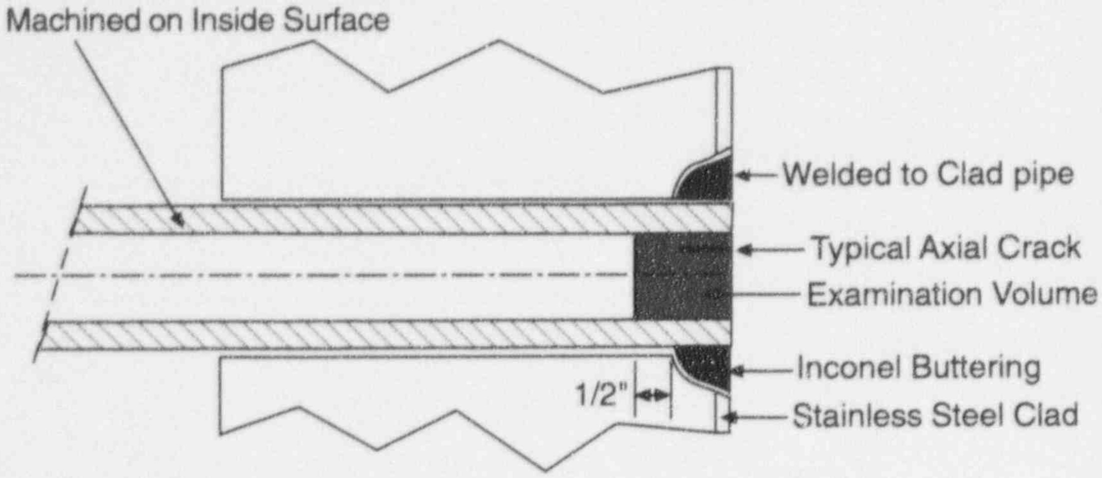


Figure 7.3-1
Examination Volume for Primary Water Stress Corrosion Cracking in Pipe Connections.

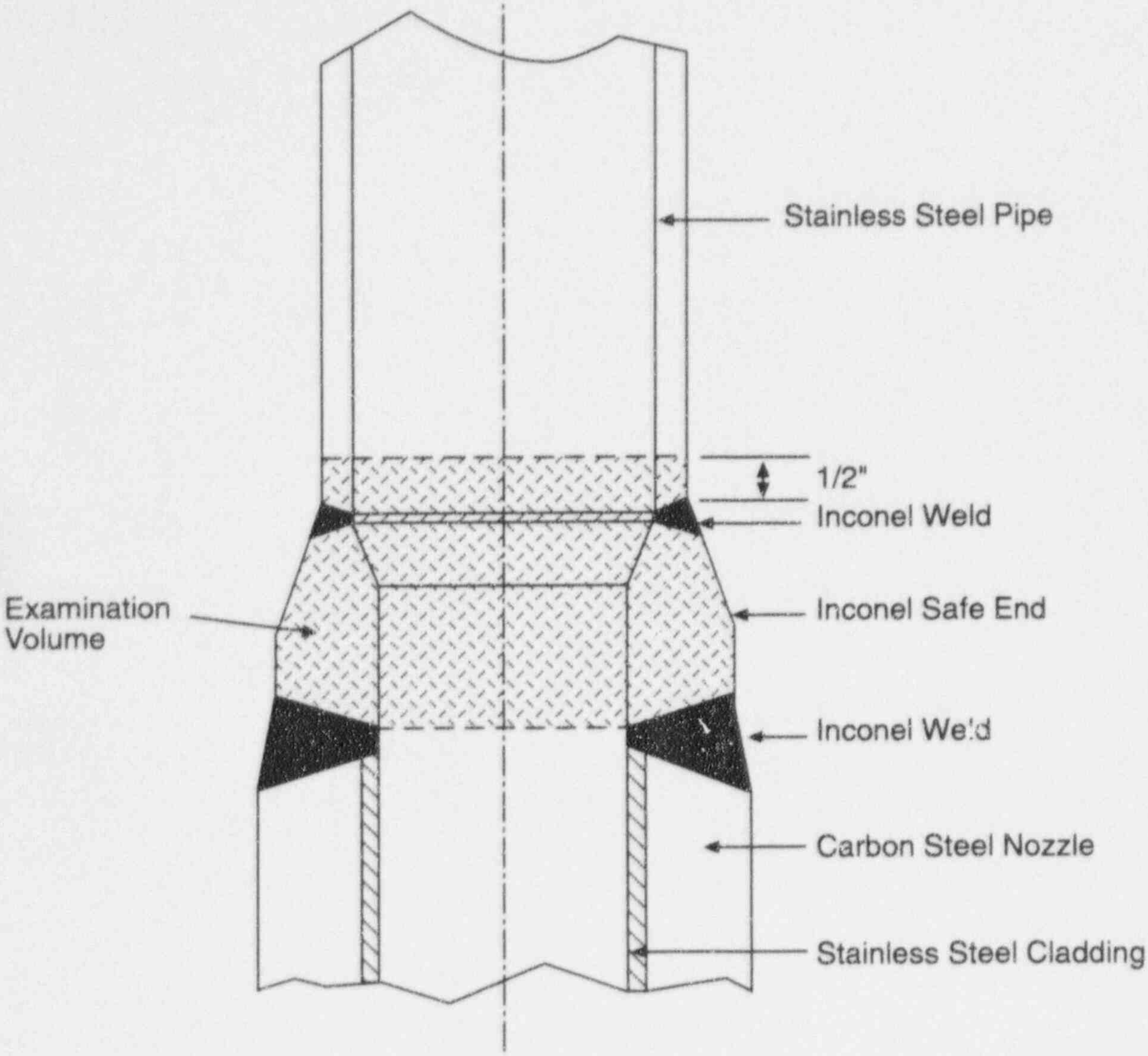


Figure 7.3-2
Examination Volume for Primary Water Stress Corrosion Cracking in Safe Ends.

7.4 Intergranular Stress Corrosion Cracking (IGSCC)

Affected Region: Welds identified to be susceptible to IGSCC, as identified in Section 4.2.4.

Examination Volumes: Volumes surrounding weld and weld heat-affected zones. Selection of welds in segments within a given risk category should be based on the relative ranking of susceptible to IGSCC as specified in NUREG-0313, Rev. 2 (e.g., the most susceptible welds are the first welds selected for examination in a segment). Examination should focus on detection of cracks initiating and propagating from the inner surface.

Examination Volume Figures: See Figures 7.4-1 through -5.

Examination Method: Ultrasonic examination is to be conducted with procedures designed specifically for detection and characterization of IGSCC.

The IGSCC morphology is intergranular, propagating in a branch-like manner along the sensitized grain boundaries in the HAZ. The length of the individual branches is generally proportional to the material grain size. In some pipe weldments, IGSCC penetrates the weld metal, but there have been no reported weld failures. Typically, IGSCC occurs nearer the weld fusion line in thicker wall components than in thin wall components. The cracks are tight and branched.

In marked contrast to carbon steel or low alloy steel where a constant ultrasonic velocity is normally encountered, the elastic anisotropy in austenitic weld material caused by the columnar grain structure leads to variations in propagation. Velocity and attenuation variations in the different directions, beam diffraction, beam skewing, reflection, refraction, and mode conversion occur in the austenitic weld material and at its interfaces. These circumstances combine to give material noise levels that make cracks undetectable through austenitic weld metal when using standard shear wave ultrasonic examination procedures.

During examination for circumferential cracks, anomalies, such as grain boundaries at these interfaces, reflect ultrasound to produce high material noise levels. The wavy interface scatters the sound beam in unexpected directions and/or produces undesirable reflections. However, circumferential IGSCC in the HAZ of austenitic welds has been detected successfully with ultrasonic techniques because, in this case, the sound beam does not pass through the weld metal.

The dendritic structure of the weld acts somewhat like a wave guide diverting the shear wave sound beam from the intended direction. Beam divergence makes indication location difficult. When searching for axial cracks, the beam divergence is worse because almost the entire sound path lies in weld metal. The austenitic weld metal severely attenuates and scatters the shear wave beam and limits the effectiveness of the examination. The high attenuation limits penetration of the beam into the weld and the high material noise level prevents detection of significant flaws. The high attenuation and high noise level in the weld metal combine with the lack of good location information to make axial cracks undetectable using conventional, shear wave ultrasonic examination. Shear wave examinations are not capable of reliably detecting even large flaws in austenitic weld metal.

Examination techniques using refracted longitudinal wave methods have proven effective for examination of austenitic weld materials. Longitudinal waves suffer less attenuation and have a weaker dependence of velocity on anisotropy than do shear waves. Also, better penetration can be achieved with less noise, enabling detection of defects in locations not examinable with shear waves. However, a shear wave beam at a lower angle always accompanies the longitudinal wave and can be a source of additional

spurious indications that must be taken into account. Even with longitudinal waves, a high material noise level is sometimes present, which can interfere with detection of small amplitude indications.

In this application, conventional shear wave examination relies on detecting the reflection from the corner formed by the flaw and the inner surface. With longitudinal waves, the corner reflection is usually weak because of mode conversion occurring at the reflecting surfaces; however, the diffracted signal from the crack tip is of primary interest.

Where access is available to both sides of the weld, examination techniques are to be applied from the base metal on each side of the weld such that the weld and near side base metal are completely examined from the near side.

Where access to both sides of the weld is not possible, examination procedures must be modified to detect flaws oriented nominally parallel to the weld. Detection of these flaws may be achieved using both shear and longitudinal wave techniques from one side of the weld and weld crown. The weld should be ground flush or flat-topped and the weld and far side base metal should be examined using refracted longitudinal and shear wave search units by scanning across the accessible base metal and weld. As a minimum, a 45° shear and longitudinal wave should be applied from the accessible weld crown. When examining from the weld surface, it might be necessary to scan at less than 3 inches per second.

Longitudinal wave frequencies lower than 2 MHz might be required for detection of flaws on the opposite side of the weld. This is permitted, provided a minimum signal-to-noise ratio of 10 to 1 is achieved from the inside surface notch in the basic calibration block. The search unit band width should be greater than 30%.

To effectively cover the examination area, it might be necessary to use shear wave search units with nominal angles of 45, 60, and 70°, as well as additional search units producing those angles with longitudinal waves.

No techniques are currently qualified for determining the length of reflectors using either shear or longitudinal waves through austenitic weld metal.

Acceptance Standard: Section XI, IWB - 3514

Evaluation Standard: Section XI, IWB - 3640

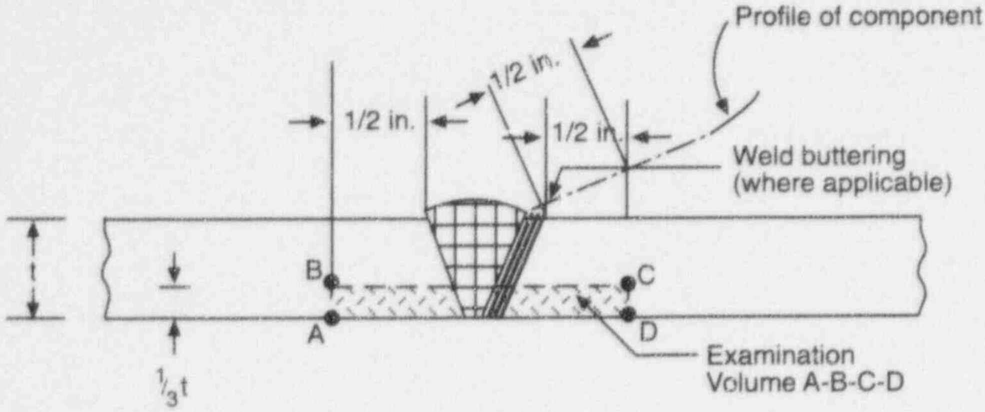


Figure 7.4-1
Examination Volume for IGSCC in Piping Welds less than NPS 4.

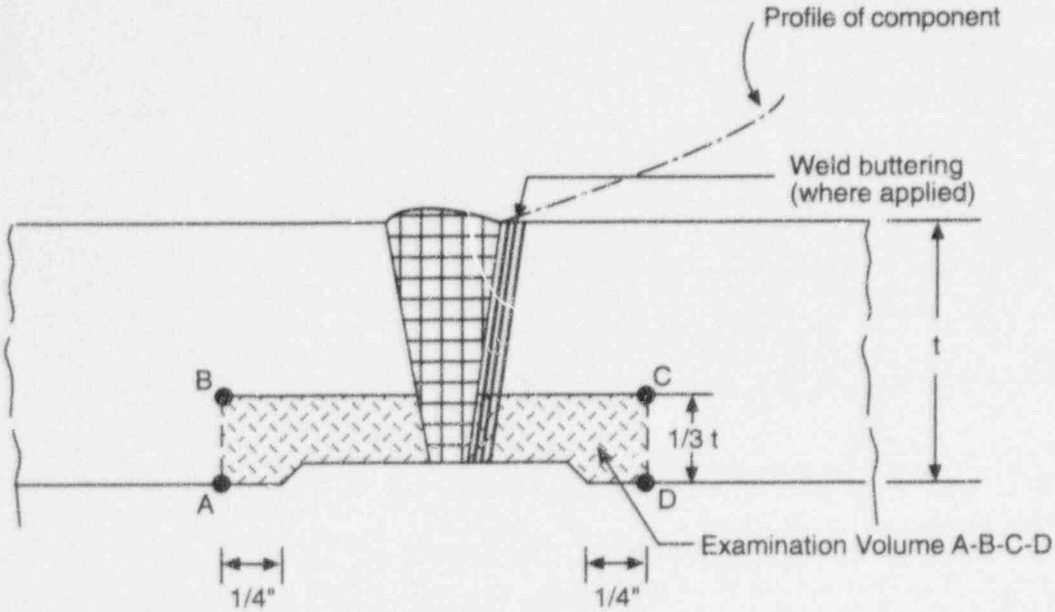


Figure 7.4-2
Examination Volume for IGSCC in Piping Welds NPS 4 or Larger.

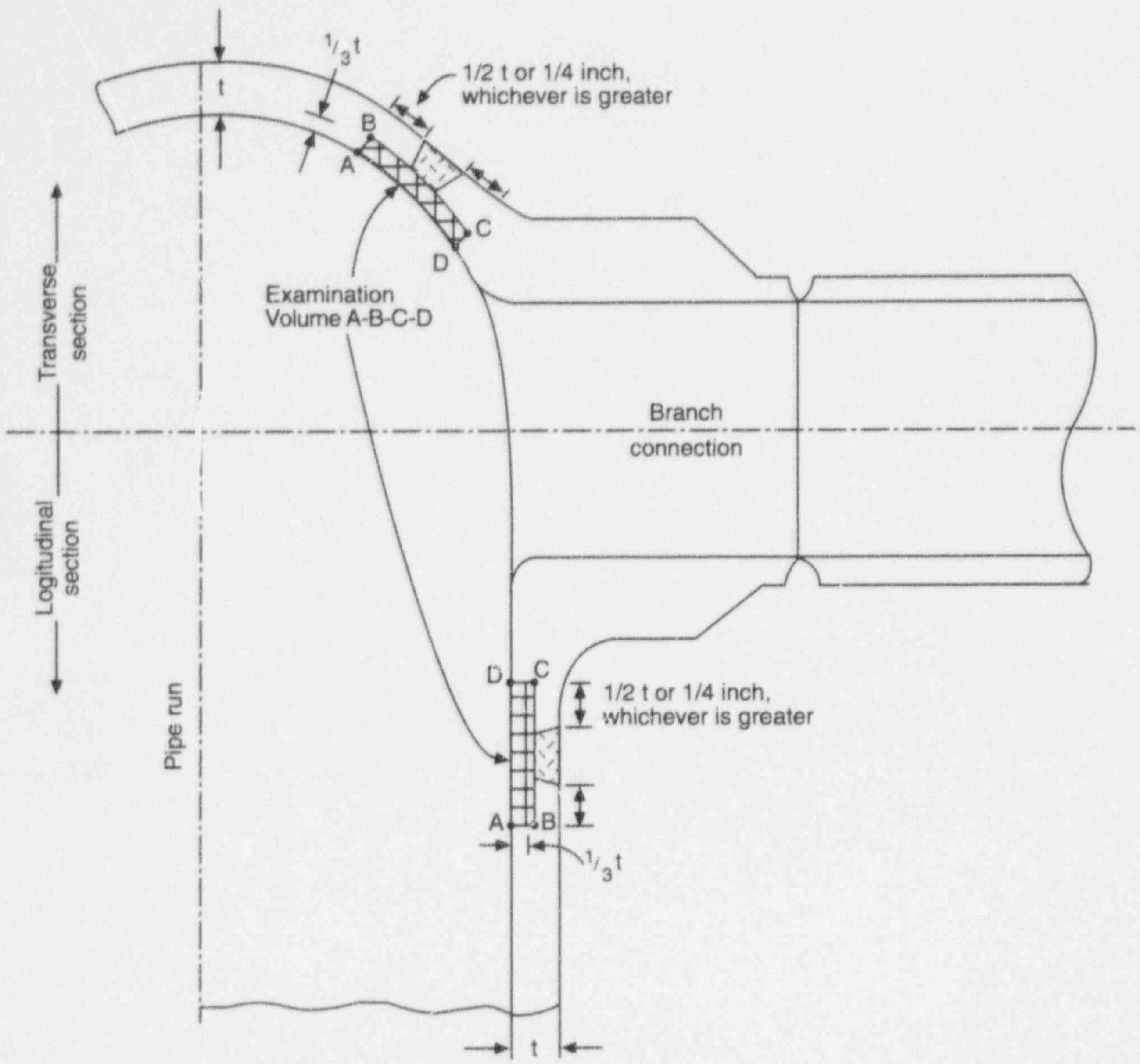


Figure 7.4-3
Examination Volume for IGSCC in Branch Connections.

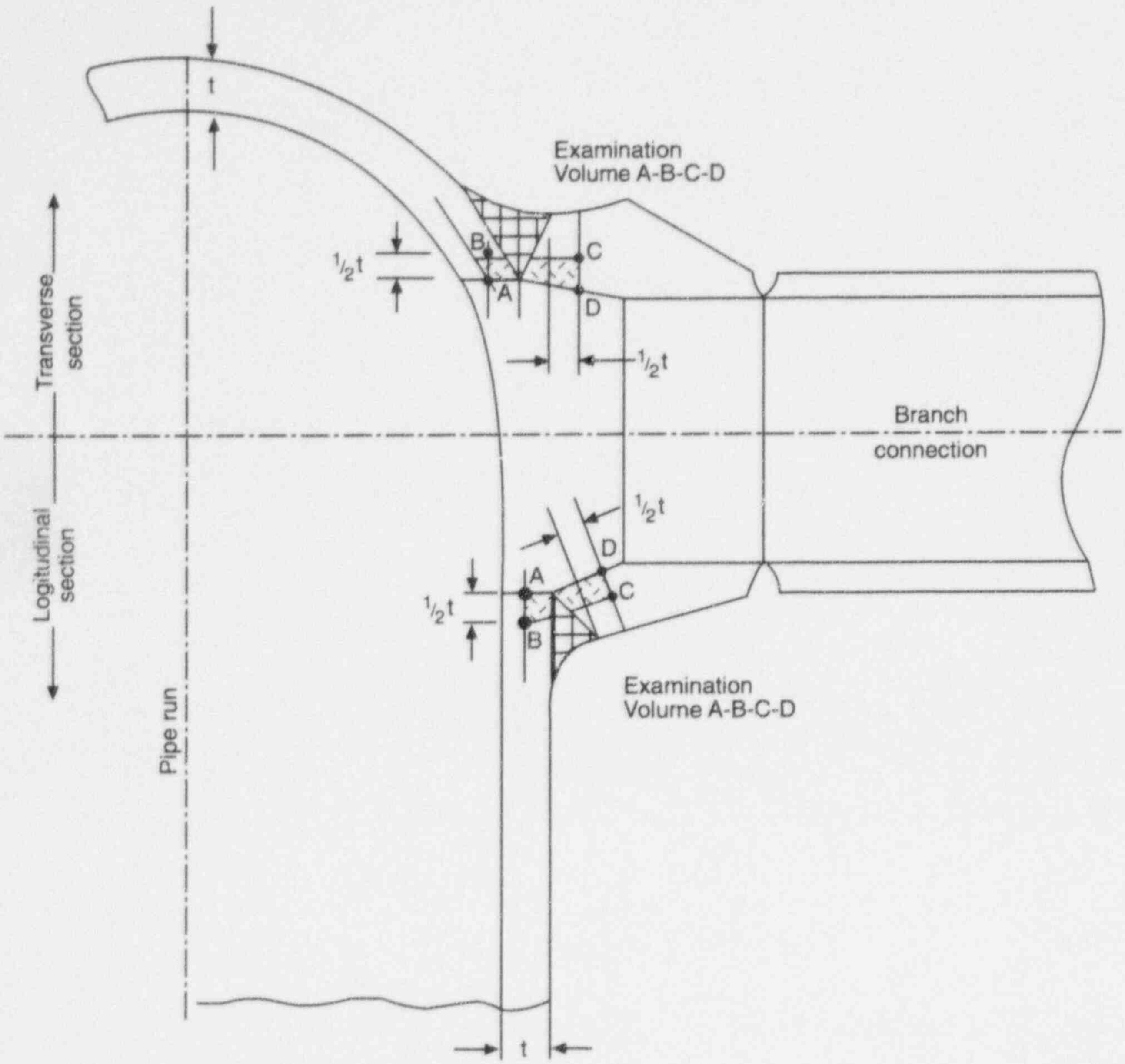


Figure 7.4-4
Examination Volume for IGSCC in Branch Connections.

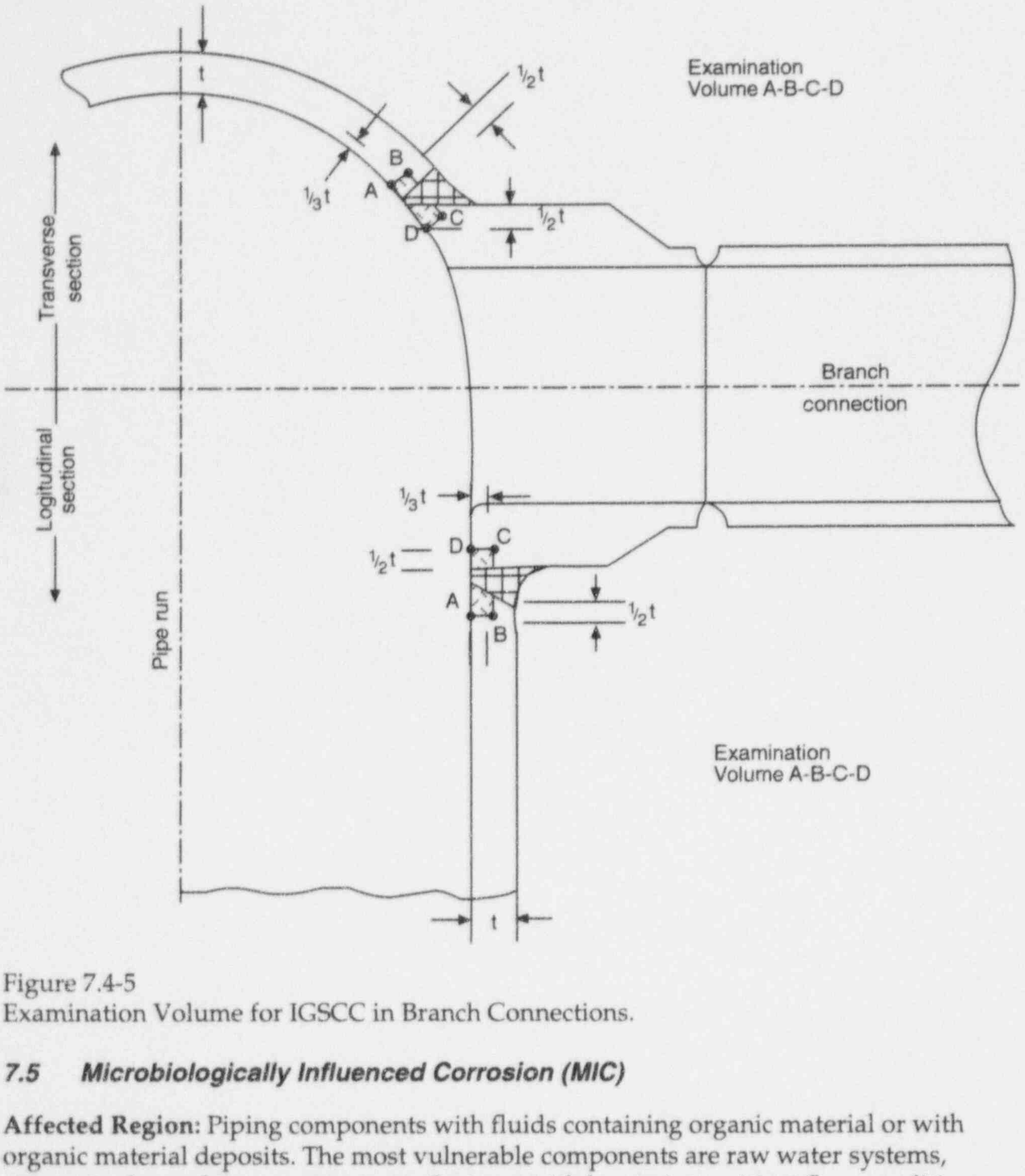


Figure 7.4-5
Examination Volume for IGSCC in Branch Connections.

7.5 Microbiologically Influenced Corrosion (MIC)

Affected Region: Piping components with fluids containing organic material or with organic material deposits. The most vulnerable components are raw water systems, storage tanks, and transport systems. Systems with low to intermittent flow conditions, temperatures between 20-120°F, and pH below 10 are primary candidates.

Examination Volumes: Base metal, welds and weld heat-affected zones in the affected regions of carbon and low alloy, and the welds and weld heat-affected zones in the affected regions of austenitic steel. The examinations should focus on regions where the degradation appears to be most prevalent as determined by visual inspection as described below in Examination Method section.

Examination Volume Figures: See Figure 7.5-1.

Examination Method: The examination method should be coupled with a monitoring program that defines the biological population found in the system. Visual techniques give indications when observations are made immediately upon opening a system. The presence of sludge/silt, metal sulfides, malodors, and general fouling/deposition are preliminary indicators of the possibility of MIC.

It is very important when examining components for MIC degradation to identify what the damage mechanisms will look like, as it will have a dramatic effect on the examination results. For example, uniform thinning is relatively easy to detect with ultrasonic examination, while pitting or tunneling might be easier to detect with radiography and quantified with ultrasonic examination. It is possible to detect pitting and tunneling with ultrasonic techniques. However, it might require slower scan speeds, higher instrument gain settings, and more sensitive transducers. In severe cases, tunneling damage results in a complete loss of ultrasonic signals.

Examination personnel should also be aware of the potential damage mechanisms so that they can select the appropriate examination method and procedure. Ultrasonic examination personnel need to be aware of the signal characteristics that might be associated with the damage mechanism.

For ultrasonic examinations, the complete area of interest should be examined, as MIC damage can be random. Grid patterns can be used with the entire grid scanned and the thin reading recorded. If point thickness readings are taken, it is important to consider that the probability of detection of thin locations has been reduced.

Acceptance Standard: IWB-3514

Evaluation Standard: Wall thinning can be evaluated using the guidelines in ASME Code Case N-480. Pitting can be evaluated by using ASME Code Case N-480 where the degraded wall thickness is $t - t_r$, and t_r is determined from the relationship t_r = total volume of the detected pitting in the inspected length of pipe (circumferential extent of pitting x axial extent of pitting in the inspected region). The total pitting volume of the affected region can be determined by rectangular areas that encompass the degraded volume of pipe material.

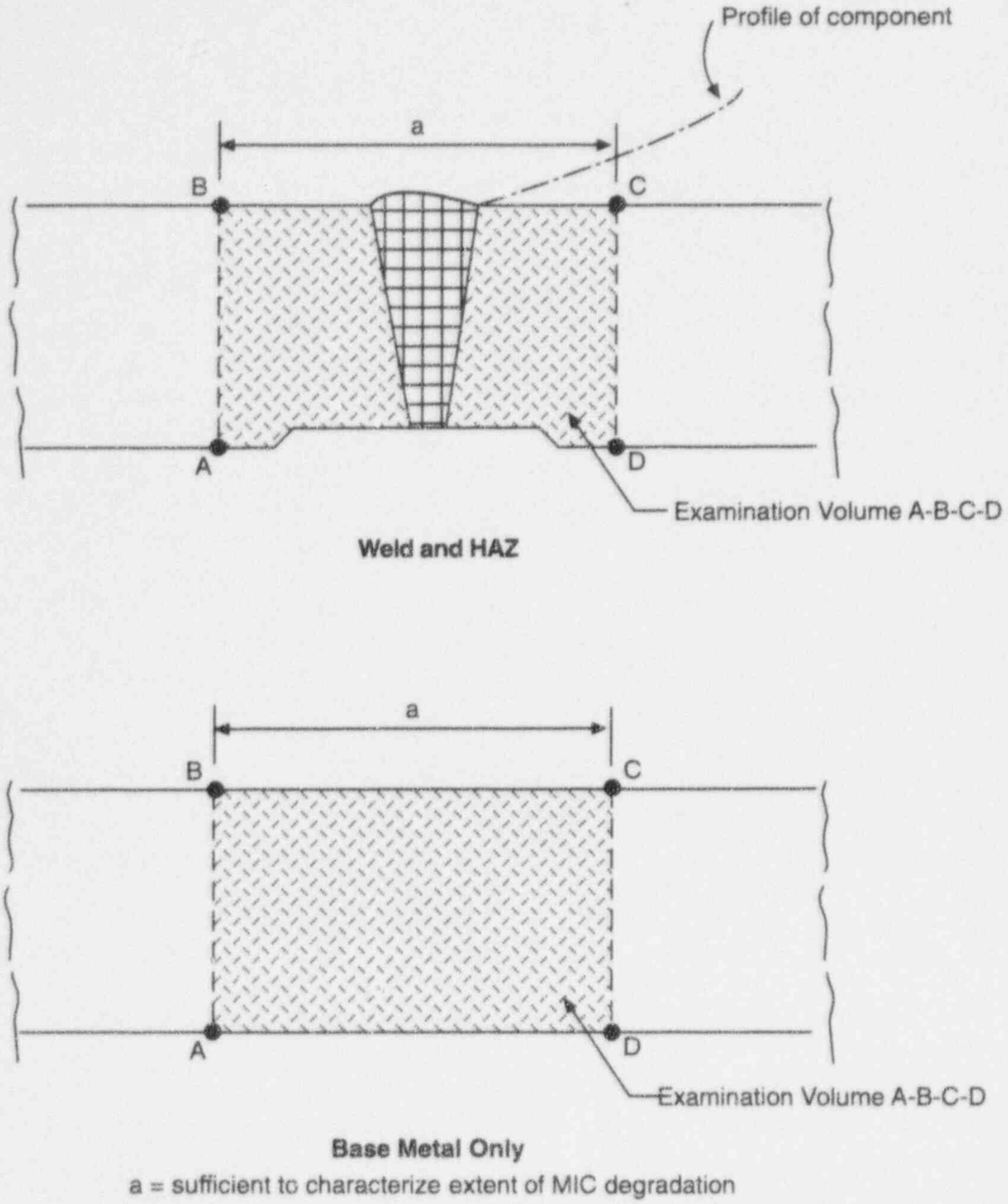


Figure 7.5-1
Examination Volume for MIC.

7.6 Erosion-Cavitation

Affected Region: Regions where (p_d - p_v)/ Δp < 5 psi, and V > 30 ft/sec., and fluid temperature < 250°F are considered susceptible to degradation from erosion-cavitation, where p_d is the static pressure downstream of the unit (pump, valve, etc.), p_v is the vapor pressure, Δp is the pressure differential across the unit, and V is the flow mean

velocity at the inlet of the unit. Standard reducers do not create the potential for erosion degradation. Regions where flow occurs for less than 20 hrs./yr. are not considered susceptible to degradation from erosion-cavitation.

Examination Volumes: The volume of material, including base metal, welds, and weld heat-affected zone, within 5D downstream of the cavitation source. If an elbow is within 5D of the cavitation source, then the affected region extends to the first weld past the elbow. Examination should focus on wall thinning from the inside surface. The actual volume selected within the 5D length can be determined in a manner similar to that used to define the inspection region for the plant FAC inspection program (see Section 7.7).

Evaluation Volume Figures: See Section 7.7, Flow-Acelerated Corrosion (FAC).

Examination Method: Erosion-cavitation is detectable with visual, ultrasonic, or radiographic examination methods. The preferred NDE method depends on the specific location where erosion-cavitation is expected, but may include ultrasonic thickness measurements, radiographic tangential and double wall techniques, as well as visual examination.

Acceptance Standard: See Section 7.7, FAC.

Evaluation Standard: See Section 7.7, FAC.

7.7 Flow-Accelerated Corrosion (FAC)

Affected Region: Component base metal regions susceptible to FAC, as identified in Section 4.2.7.

Examination Volumes: Volume of material susceptible to FAC as identified in the existing plant FAC inspection program, or for the purpose of RISI identified in accordance with the plant FAC evaluation criteria.

Examination Volume Figures: See Figures 7.7-1 through -7.

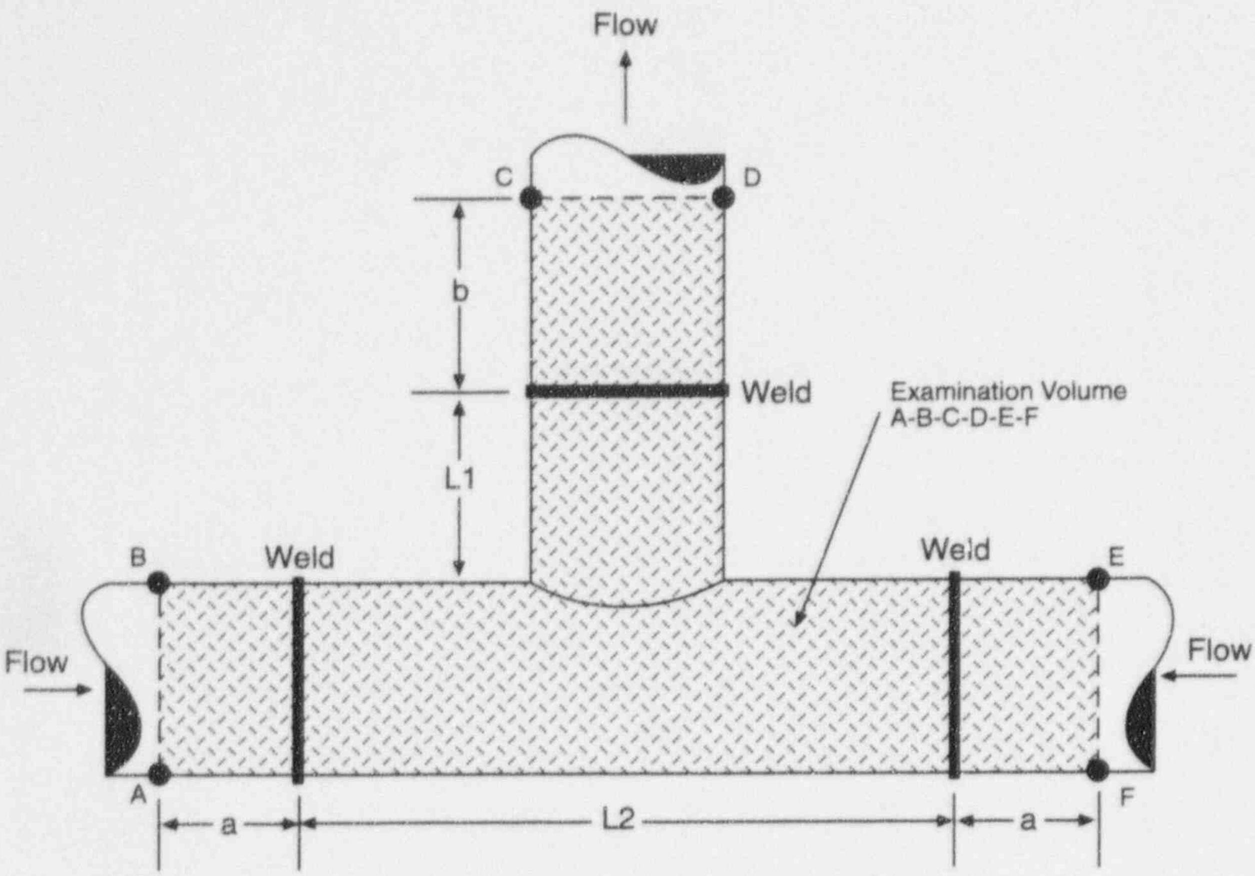
Examination Method: Volumetric. Manual ultrasonic examination is typically used to detect and measure component walls for single and two phase FAC. Most piping systems that are susceptible to FAC operate at elevated temperatures, hence they have insulation that must be removed and the surface prepared prior to the ultrasonic examination. Because the damage mechanism is gradual wear over an area rather than isolated thickness loss, spot thickness readings at predetermined locations can be done rather than 100% examination. The spot thickness locations should be identified in a procedure that provides a method of gridding the component in a repeatable fashion. The thickness readings should be taken at the grid intersections. It is important that the location of each thickness reading be repeated for future examinations, as thickness data is often used to identify and trend pipe wear.

Although the ultrasonic technique used for acquiring thickness data is one of the least complicated ultrasonic techniques, it is important that adequate procedures are in place to ensure accurate repeatable results. Equipment selection is one of the more important variables associated with this technique. Transducers must be selected based on the applicable thickness range. It is also important to use an ultrasonic instrument with an A-scan presentation so that volumetric reflectors do not provide inaccurate data. Portable digital thickness gauges with A-scan presentations are available and have been found to provide adequate results.

As an alternative to ultrasonic examination, radiography can be used to detect and measure FAC. However, the procedure is generally limited to pipes of 6-inch NPS and less because of long exposure times for larger diameter piping. A tangential radiographic technique that aligns the source, pipe wall, and film can be used to obtain quantitative thickness data, however several shots are required to examine a component. The primary benefit of radiography is that it can be used to examine components with insulation in place, eliminating the cost associated with insulation removal and reinstallation. Radiography also provides better data on socket welded components than ultrasonics.

Acceptance Standard: According to the plant FAC program.

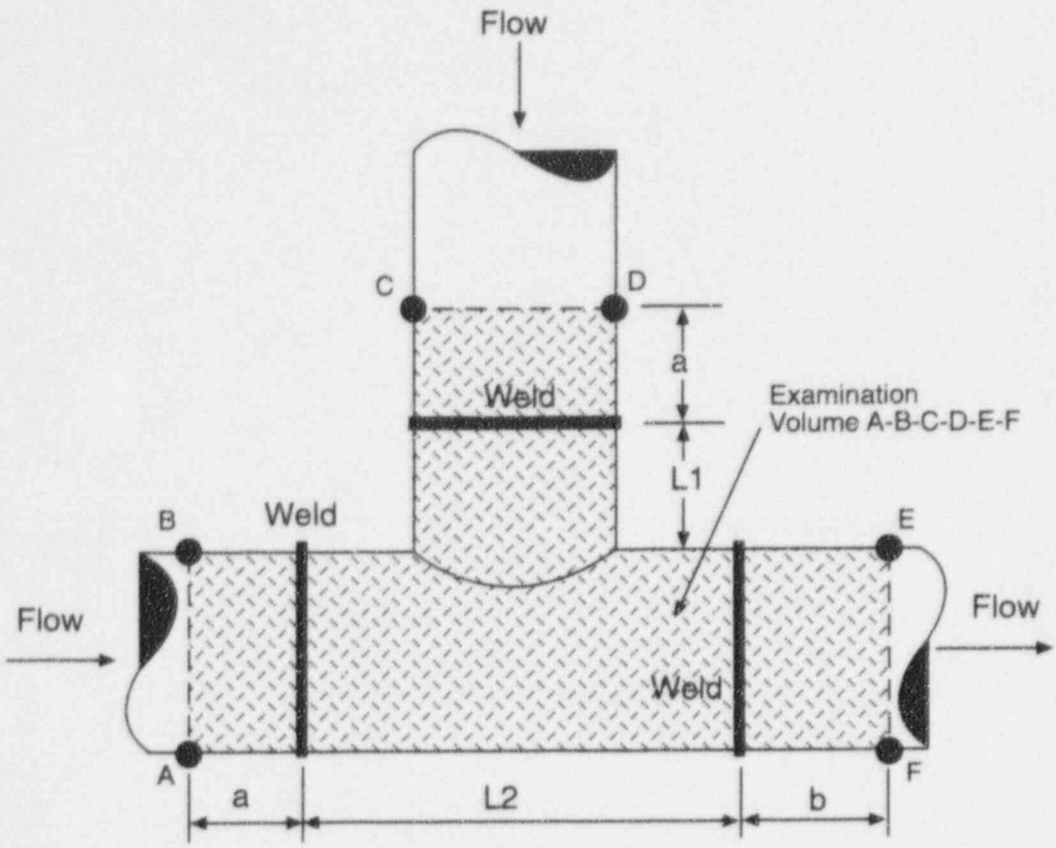
Evaluation Standard: According to the plant FAC program.



a = minimum of 2 grid lines

b = minimum of 2 grid lines or 6 inches, whichever is greater

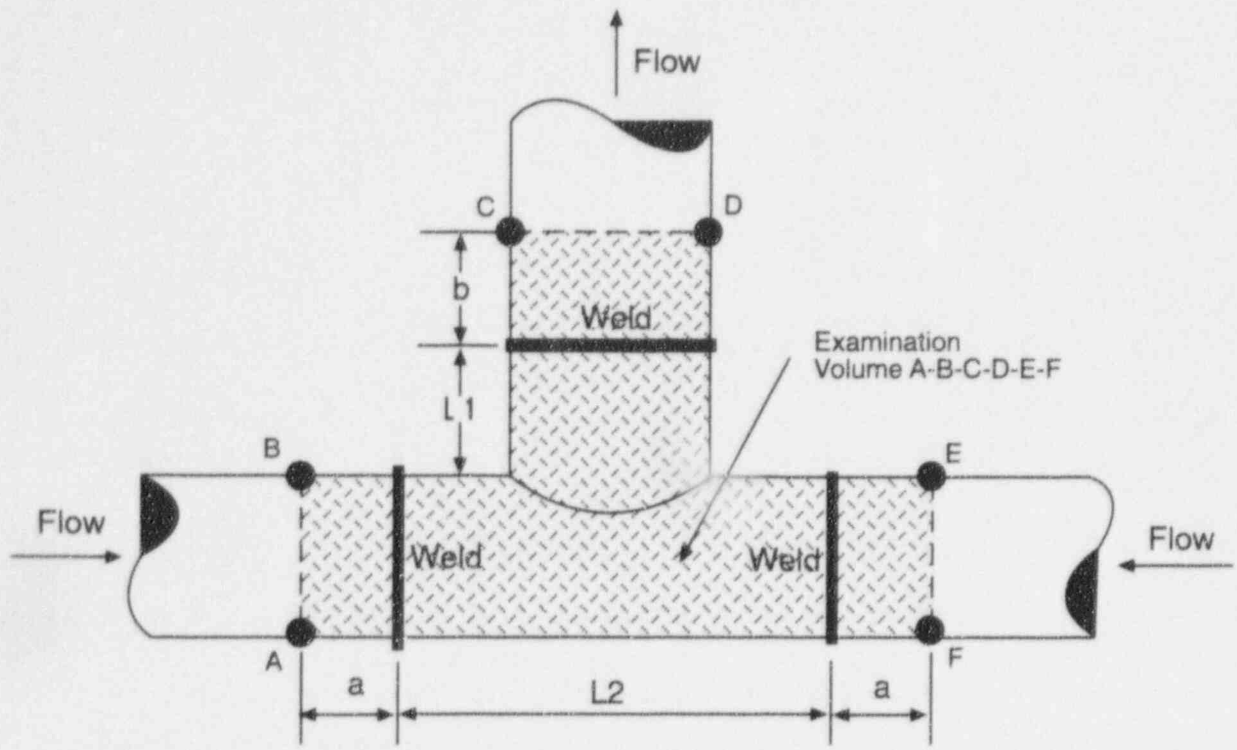
Figure 7.7-1
Examination Area for FAC.



a = minimum of 2 grid lines

b = minimum of 2 grid lines or 6 inches, whichever is greater

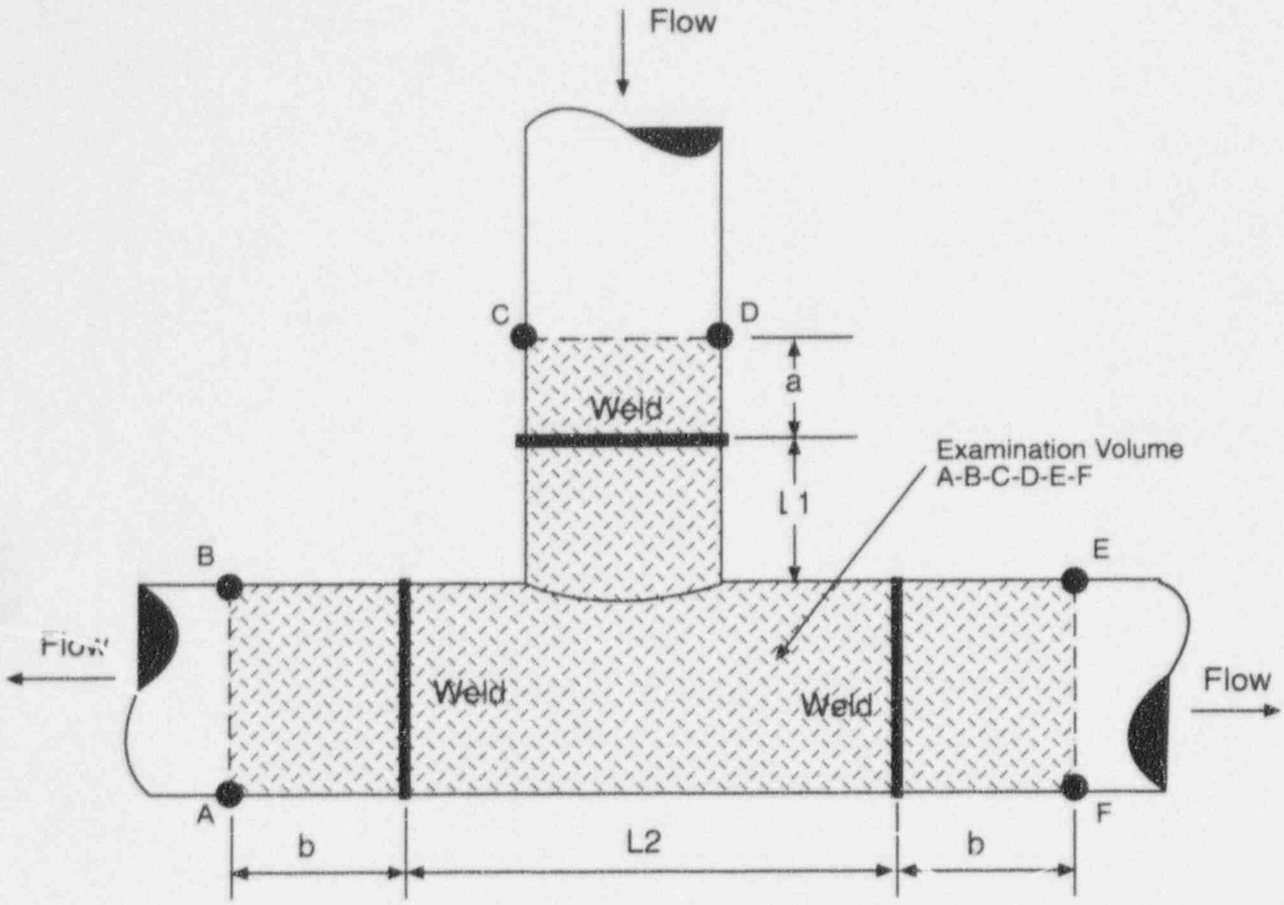
Figure 7.7-2
Examination Area for FAC.



a = minimum of 2 grid lines

b = minimum of 2 grid lines or 6 inches, whichever is greater

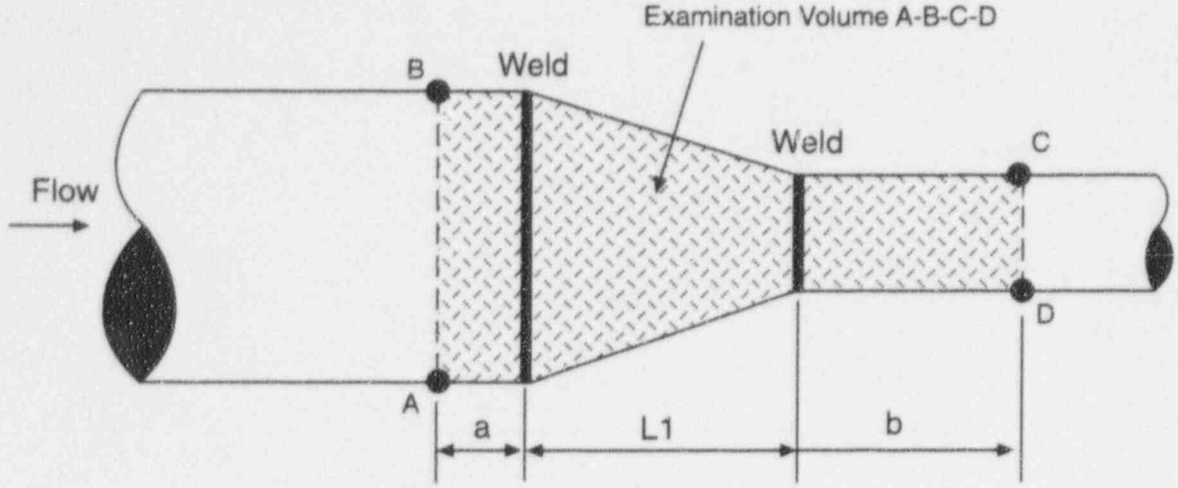
Figure 7.7-3
Examination Area for FAC.



a = minimum of 2 grid lines

b = minimum of 2 grid lines or 6 inches, whichever is greater

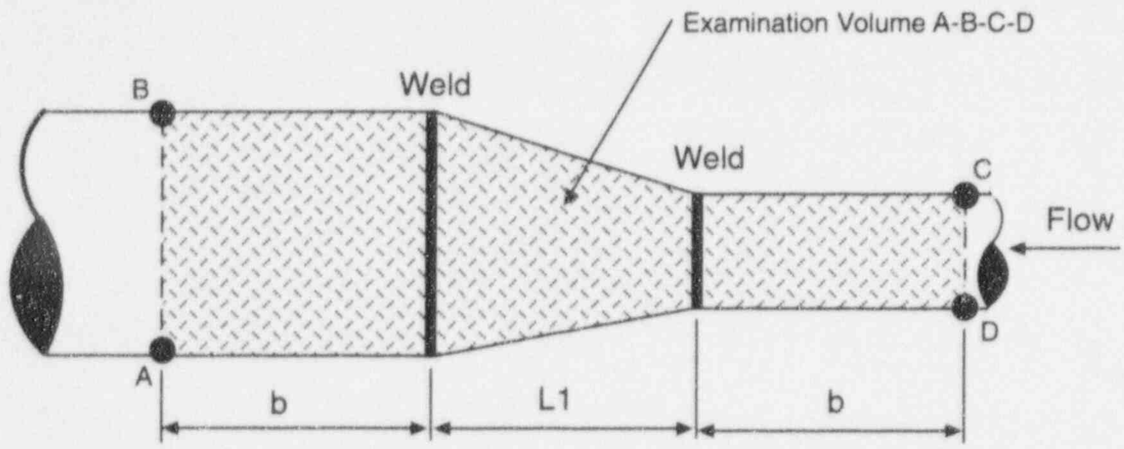
Figure 7.7-4
Examination Area for FAC.



a = minimum of 2 grid lines

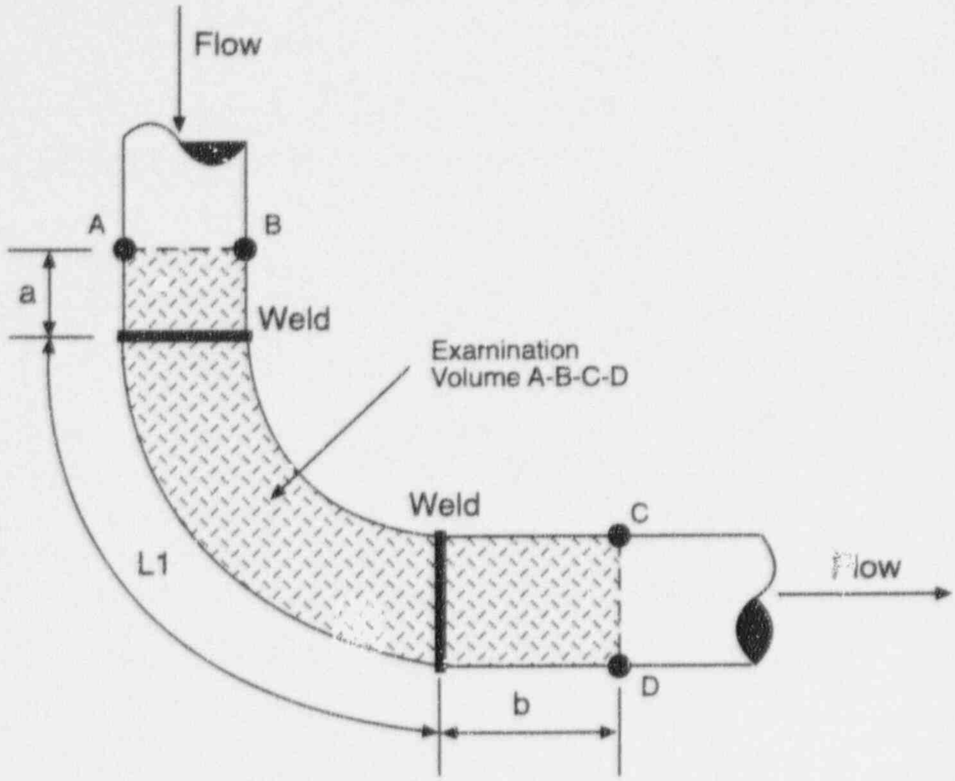
b = minimum of 2 grid lines or inches, whichever is greater

Figure 7.7-5
Examination Area for FAC.



b = minimim of 2 grid lines or 6 inches, whichever is greater

Figure 7.7-6
Examination Area for FAC.



a = minimum of 2 grid lines

b = minimim of 2 grid lines or 6 inches, whichever is greater

Figure 7.7-7
Examination Area for FAC.

8

PLANT INFORMATION REQUIREMENTS AND DOCUMENTATION

8.1 Plant Information Requirements

The evaluation process begins with providing information that will determine the scope of the analysis. This information is necessary for defining the systems to be analyzed, and the boundaries of those systems, and identifying the elements to be evaluated within the system boundaries. The information needed for the evaluation process is summarized as follows:

Hard Copy

- ISI program plan
- ISI isometrics
- P&IDs (for applicable systems)
- Spatial databases (IPE/IPEEE/Appendix R, etc.)
- Flooding/spray studies (IPE/IPEEE/MELB/HELB)
- System training manuals
- PSA Information (PRA/IPE/IPEEE)
- Material specifications
- Line lists
- Valve lists
- System design basis documents
- Flow-accelerated corrosion (FAC) program description
- IGSCC program description
- Plant service experience (i.e., cracking, water hammer, FAC event history, etc.)

Personnel Support

- ISI personnel
- PRA personnel
- System/design engineers
- Walkdown access

Miscellaneous

- Cost drivers (i.e., which systems, locations, etc.)

8.2 Documentation

Documentation of the RISI effort involves two general requirements: 1) documentation of the risk-informed evaluation, and 2) documentation of the revised ISI program. This section discusses those attributes that will be useful in providing the necessary documentation. As ISI programs for all plants must meet the requirements of 10CFR50, Appendix B, documentation supporting the revised ISI program must also meet the utilities' quality assurance requirements.

The intent of the documentation requirements identified herein are twofold. The first intent is to provide evidence of the risk-informed evaluation effort and its inputs. Generally, this Tier 1 information will be retained, documented, and organized in the FMEA database. As such, this database should provide a readily retrievable and auditable evaluation package. An additional level of documentation is required to support the Appendix B review of the evaluation as well as a means for future re-creation and/or modification of the risk-informed effort. This Tier 2 documentation tends to consists of marked-up drawings and supplemental calculations that will need to be retained in hard copy or microfilmed/fiched media.

8.2.1 Tier 1 Documentation—FMEA Database

The information necessary to support the risk-informed evaluation is required to meet the utility's quality assurance program requirements. Summary information can be retained in the FMEA database. This database should contain the following information:

Element Information: This type of information consists of the type of element, its location, system ID, and current ISI status. A typical report form is presented in Table 8-1.

Segment Information: Provides information on segment identification, description, elements included, and consequence of failures. A typical report form is presented in Table 8-2.

Degradation Mechanism Identification: Identifies applicable degradation mechanisms for each element and the basis for its assignment. A typical report form is presented in Table 8-3.

Consequence Evaluation: Contains information on the impact of individual failures; spatial effects, initiating events system impacts, recovery potential, etc. Typical report forms are presented in Table 8-4a and 4b.

Risk Evaluation: For each segment, summary information is provided that contains applicable degradation mechanisms, leak size, consequences, and risk category. A typical report form is presented in Table 8-5.

8.2.2 Tier 2 Documentation

Tier 2 documentation is required to support the review of the evaluation effort and to provide a means of re-creating and/or modifying the results. This type of information generally consists of marked-up drawings and supplemental calculations that need to be retained in hard copy or microfilm. Tier 2 documentation contains the following types of information:

Piping System Configuration

The information needed to support this task consists of the following:

- Current ISI program
- ISI isometric drawings
- P&IDs
- Piping design specification
- Material and fabrication specification
- Inspection cost data

Marked-up drawings detailing system boundaries and analysis boundaries need to be retained.

Damage Mechanisms

In addition to the above, the information needed to support this task consists of the following:

- System training manuals
- Design basis documents
- Operating conditions
- Plant-specific service experience
- Line lists

Supplemental calculations and additional sources of information (telecons, interviews, etc.) need to be retained.

Consequence Evaluation

In addition to the above, the data needed to support this task consists of the following:

- FSAR
- Spatial databases (such as IPEEE, Appendix R, etc.)
- Flooding/spray studies (such as HELB, MELB, IPEEE, etc.)
- PRA analyses (e.g., IPE, IPEEE)

Table 8-1
FMECA - Element Identification and ISI Status

System ID	Segment	Line Number	Line Description	Weld Number	Weld Location	Weld Type	Weld Material	Weld Class	Examination Category	Category Item	Current Examination
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	5	Upstream side of Elbow - Downstream from RH-V15	Butt	SS	1			
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	4	Field Weld Downstream side of Elbow - Downstream from RH-V15	Butt	SS	1	B-J	B9.11	V,S
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	3	Upstream side of Elbow - Downstream from RH-V15	Butt	SS	1	B-J	B9.11	V,S
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	2	Downstream side of Check Valve RH-V15	Butt	SS	1	B-J	B9.11	V,S
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	9	Field Weld Upstream side of RH-V59	Butt	SS	1			
LPSI-A	LPSI-A33	RH-0155-05-2501-6	RHR to Cold Leg 1	13	Upstream side of Elbow - Downstream from RH-V59	Butt	SS	1			
LPSI-A	LPSI-A33	RH-0155-05-2501-6	RHR to Cold Leg 1	19	Upstream side of Reducer - Downstream from RH-V59	Butt	SS	1			
LPSI-A	LPSI-A33	RH-0155-05-2501-6	RHR to Cold Leg 1	18	Downstream side of Elbow - Downstream from RH-V59	Butt	SS	1			
LPSI-A	LPSI-A33	RH-0155-05-2501-6	RHR to Cold Leg 1	17	Upstream side of Elbow - Downstream from RH-V59	Butt	SS	1			
LPSI-A	LPSI-A33	RH-0155-05-2501-6	RHR to Cold Leg 1	16	Downstream side of Elbow - Downstream from RH-V59	Butt	SS	1			

Table 8-2
FMECA - Segment Identification

Segment	Segment Description	Line Number	Welds	Number of Welds	Pipe Diameter (inches)	Segment Wall Thickness (inches)
LPSI-A01	RHR Pump A (RH-P-8A) Discharge to Check Valve RH-V4	RH-0151-01-0601-8	1, 2, 32	3	8	0.322
LPSI-A02	RHR Pump A Discharge Between Check Valve RH-V4 and FE-610	RH-0151-01-0601-8	3, 31, 4, 5, 6, 7, 8	7	8	0.322
LPSI-A03	RHR Pump A Discharge, Outlet of FE-610 (Erosion)	RH-0151-01-0601-8	9	1	8	0.322
LPSI-A04	RHR Pump A Discharge, Outlet of FE-610 (No Erosion)	RH-0151-01-0601-8	10	1	8	0.322
LPSI-A05	RHR Pump A Discharge, Between FE-610 and Manual Valve RH-V9 (IGSCC)	RH-0151-01-0601-8	11, 12	2	8	0.322
LPSI-A06	RHR Pump A Discharge, Between FE-610 and Manual Valve RH-V9, including Manual Valve RH-V9 Line	RH-0151-01-0601-8	13, 14, 15, 16, 17, 18, 19, 20, 21, 22	10	8	0.322
LPSI-A07	RHR Pump A Discharge, Between Manual Valve RH-V9 and RHR Heat Exchanger (RH-E-9A) (IGSCC)	RH-0151-01-0601-8	23, 24	2	8	0.322
LPSI-A08	RHR Pump A Discharge, Between Manual Valve RH-V9 and RHR Heat Exchanger (RH-E-9A) (No IGSCC)	RH-0151-01-0601-8	25, 26	2	8	0.322

Table 8-3
FMECA - Degradation Mechanisms

System ID	Segment	Line Number	Line description	Weld Number	Weld Location	T	CC	PW	I	M	E
LPSI-A	LPSI-A30	RH-0155-04-2501-6	RHR to Cold Leg 1	3	Field Weld Downstream side of Flange for FE-2557	N	N	N	N	N	S
LPSI-A	LPSI-A31	RH-0155-05-2501-6	RHR to Cold Leg 1	1	Upstream side of Check Valve RH-V15	N	N	N	N	N	N
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	7	Upstream side of Elbow - Downstream from RH-V15	N	N	N	N	N	N
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	8	Downstream side of Elbow - Downstream from RH-V15	N	N	N	N	N	S
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	6	Downstream side of Elbow - Downstream from RH-V15	N	N	N	N	N	N
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	5	Upstream side of Elbow - Downstream from RH-V15	N	N	N	N	N	N
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	4	Field Weld Downstream side of Elbow - Downstream from RH-V15	N	N	N	N	N	N
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	3	Upstream side of Elbow - Downstream from RH-V15	N	N	N	N		S
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	2	Downstream side of Check Valve RH-V15	N	N	N	N	N	N
LPSI-A	LPSI-A32	RH-0155-05-2501-6	RHR to Cold Leg 1	9	Field Weld Upstream side of RH-V59	N	N	N	N	N	N

Degradation Mechanisms

T - Thermal Fatigue
CC - Corrosion Cracking
PW - Primary Water Stress Corrosion Cracking (PWSCC)
I - Intergranular Stress Corrosion Cracking (IGSCC)
M - Microbiologically Influenced Corrosion (MIC)
E - Erosion - Cavitation
EE - Erosion - Corrosion
O - Other

Table 8-4a
FMECA - Consequences - Spatial Effects

Segment	Segment Description	Line Number	Welds	Break Size	Isolability of Break	ISO Comments	Spatial Effects
LPSI-A31	RHR Cold Leg 1 Injection, Check Valve RH-V15 Inlet	RH-0155-05-2501-6	1	Large	Yes	Break needs to be isolated in order to prevent a loss of RWST volume. RWST can be isolated by closing MOV RH-V14 (in CE/PP) or MOV CBS-V2 (RHR-Vault1).	Local
LPSI-A32	RHR Cold Leg 1 Injection, Between Check Valve RH-V15 and Valve RH-V59	RH-0155-05-2501-6	2, 3, 4, 5, 6, 7, 8, 9	Large	Yes	Break needs to be isolated in order to prevent a loss of RWST volume. RWST can be isolated by closing MOV RH-V14 (in CE/PP) or MOV CBS-V2 (RHR-Vault1).	Local
LPSI-A33	RHR Cold Leg 1 Injection, Between Valve RH-V59 and Common Header with Accumulator	RH-0155-05-2501-6	10, 11, 12, 13, 14, 15, 16, 17, 18, 19	Large	Yes	Break needs to be isolated in order to prevent a loss of RWST volume. RWST can be isolated by closing MOV RH-V14 (in CE/PP) or MOV CBS-V2 (RHR-Vault1).	Local

Table 8-4b
FMECA - Consequences - Impact

Segment	Segment Description	Line Number	Weld Numbers	Initiating Event	Initiating Event ID	Initiating Event Recovery	Loss of System	IPE System ID	System Recovery	Loss of Train	Train ID	Train Recovery
LPSI-A32	RHR Cold Leg 1 Injection, Between Check Valve RH-V15 and Valve RH-V59	RH-0155-05-2501-6	2, 3, 4, 5, 6, 7, 8, 9	None			No			M-2	LPSI-A, CBS-A	It is assumed that two trains can be lost because an operator can select to close MOV CBS-V2, in order to isolate the break. If break is isolated by closure of MOV RH-V14, only LPSI-A will be lost. SI injection to Cold Leg 1 can be affected. The efect is not considered significant.
LPSI-A33	RHR Cold Leg 1 Injection, Between Valve RH-V59 and Common Header with Accumulator	RH-0155-05-2501-6	10, 11, 12, 13, 14, 15, 16, 17, 18, 19	None			No			M-2	LPSI-A, CBS-A	It is assumed that two trains can be lost because an operator can select to close MOV CBS-V2, in order to isolate the break. If break is isolated by closure of MOV RH-V14, only LPSI-A will be lost. SI injection to Cold Leg 1 can be affected. The efect is not considered significant.

Table 8-4a
FMECA - Consequences - Spatial Effects

Segment	Segment Description	Line Number	Welds	Break Size	Isolability of Break	ISO Comments	Spatial Effects
LPSI-A31	RHR Cold Leg 1 Injection, Check Valve RH-V15 Inlet	RH-0155-05-2501-6	1	Large	Yes	Break needs to be isolated in order to prevent a loss of RWST volume. RWST can be isolated by closing MOV RH-V14 (in CE/PP) or MOV CBS-V2 (RHR-Vault1).	Local
LPSI-A32	RHR Cold Leg 1 Injection, Between Check Valve RH-V15 and Valve RH-V59	RH-0155-05-2501-6	2, 3, 4, 5, 6, 7, 8, 9	Large	Yes	Break needs to be isolated in order to prevent a loss of RWST volume. RWST can be isolated by closing MOV RH-V14 (in CE/PP) or MOV CBS-V2 (RHR-Vault1).	Local
LPSI-A33	RHR Cold Leg 1 Injection, Between Valve RH-V59 and Common Header with Accumulator	RH-0155-05-2501-6	10, 11, 12, 13, 14, 15, 16, 17, 18, 19	Large	Yes	Break needs to be isolated in order to prevent a loss of RWST volume. RWST can be isolated by closing MOV RH-V14 (in CE/PP) or MOV CBS-V2 (RHR-Vault1).	Local

Table 8-4b
FMECA - Consequences - Impact

Segment	Segment Description	Line Number	Weld Numbers	Initiating Event	Initiating Event ID	Initiating Event Recovery	Loss of System	IPE System ID	System Recovery	Loss of Train	Train ID	Train Recovery
LPSI-A32	RHR Cold Leg 1 Injection, Between Check Valve RH-V15 and Valve RH-V59	RH-0155-05-2501-6	2, 3, 4, 5, 6, 7, 8, 9	None			No			M-2	LPSI-A, CBS-A	It is assumed that two trains can be lost because an operator can select to close MOV CBS-V2, in order to isolate the break. If break is isolated by closure of MOV RH-V14, only LPSI-A will be lost. SI injection to Cold Leg 1 can be affected. The efect is not considered significant.
LPSI-A33	RHR Cold Leg 1 Injection, Between Valve RH-V59 and Common Header with Accumulator	RH-0155-05-2501-6	10, 11, 12, 13, 14, 15, 16, 17, 18, 19	None			No			M-2	LPSI-A, CBS-A	It is assumed that two trains can be lost because an operator can select to close MOV CBS-V2, in order to isolate the break. If break is isolated by closure of MOV RH-V14, only LPSI-A will be lost. SI injection to Cold Leg 1 can be affected. The efect is not considered significant.

Table 8-5
FMECA - Risk Ranking

Segment	Segment Description	Line Number	Welds	Number of Welds	Mechanisms	Category
LPSI-A01	RHR Pump A (RH-P-8A) Discharge to Check Valve RH-V4	RH-0151-01-0601-8	1, 2, 32	3		M
LPSI-A02	RHR Pump A Discharge Between Check Valve RH-V4 and FE-610	RH-0151-01-0601-8	3, 31, 4, 5, 6, 7, 8	7		M
LPSI-A03	RHR Pump A Discharge, Outlet of FE-610 (Erosion)	RH-0151-01-0601-8	9	1	E	M
LPSI-A04	RHR Pump A Discharge, Outlet of FE-610 (No Erosion)	RH-0151-01-0601-8	10	1		M
LPSI-A05	RHR Pump A Discharge, Between FE-610 and Manual Valve RH-V9 (IGSCC)	RH-0151-01-0601-8	11, 12	2	I	M
LPSI-A06	RHR Pump A Discharge, Between FE-610 and Manual Valve RH-V9, including Manual Valve RH-V9 Line	RH-0151-01-0601-8	13, 14, 15, 16, 17, 18, 19, 20, 21, 22	10		M
LPSI-A07	RHR Pump A Discharge, Between Manual Valve RH-V9 and RHR Heat Exchanger (RH-E-9A) (IGSCC)	RH-0151-01-0601-8	23, 24	2	I	M
LPSI-A08	RHR Pump A Discharge, Between Manual Valve RH-V9 and RHR Heat Exchanger (RH-E-9A) (No IGSCC)	RH-0151-01-0601-8	25, 26	2		M

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Appendix A

ACRONYMS AND ABBREVIATIONS

AOT	Allowed outage time
APP R	Appendix R
BWR	Boiling water reactor
CS	Carbon steel
DB	Design basis
DM	Degradation mechanism
ECCS	Emergency emergency core cooling system
FAC	Flow-accelerated corrosion
FMECA	Failure modes and effects criticality analysis
FSAR	Final safety analysis report
FWLB	Feedwater line break
HAZ	Heat-affected zone
HELB	High-energy line break
IE	Initiating event
IGSCC	Intergranular stress corrosion cracking
IPE	Individual plant examination
IPEEE	Individual plant examination - external events
ISI	Inservice inspection
LLOCA	Large loss of coolant accident
LOCA	Loss of coolant accident
LOSP	Loss of off-site power
MELB	Medium energy line break
MFW	Main feedwater
MIC	Microbiologically influenced corrosion
MLOCA	Medium loss of coolant accident
NPS	Nominal pipe size
P&IDs	Pipe and instrumentation drawings
PRA	Probabilistic risk assessment

PWR	Pressurized water reactor
PWSCC	Primary water stress corrosion cracking
RISI	Risk-informed inservice inspection
RCS	Reactor coolant system
RHR	Residual heat removal
Ri	Richardson number
SLB	Steamline break
SLOCA	Small loss of coolant accident
SS	Stainless steel (austenitic)
TASCS	Thermal stratification cycling and striping
TF	Thermal fatigue

Appendix B

GLOSSARY

AVAILABILITY. The probability that a component or system will perform a specified function or mission under given conditions at a required time.

BACKUP SYSTEM. See mitigating system.

CONSEQUENCE. The impact or the ultimate result of an event. Consequences can be measured in terms of impact on public health and safety, impact on the environment, and cost or damage to the facility. Consequence measures typically considered in the nuclear industry are core damage frequency and magnitude of release (source term).

CONTAINMENT BYPASS. Events that lead to a direct release of radioactive material to the environment bypassing the containment boundary.

CONTAINMENT ISOLATION FAILURE. The containment failure mode that results from a failure to isolate all lines that penetrate the containment.

CORE DAMAGE FREQUENCY. An estimated frequency of occurrence of events leading to core damage.

CORE DAMAGE. Uncovery and heatup of the reactor core to the point where damage to reactor fuel elements or cladding is anticipated.

DAMAGE MECHANISM. See degradation mechanism.

DEGRADATION MECHANISM. Phenomena or process that attacks (wear, cracking, etc.) the pressure-retaining material and might result in a reduction of component pressure boundary integrity.

EXTERNAL EVENT. An event that initiates outside of plant systems and results in the perturbation of steady-state plant operation (e.g., seismic event, tornado, etc.).

FAILURE MODES, EFFECTS, AND CRITICALITY ANALYSIS (FMECA). A detailed technique specifically designed to identify the failure modes of an analyzed component, the impacts of the failure on operations, the system and surrounding components, and controls for limiting the likelihood of such failures.

INITIATING EVENT. An event that perturbs steady-state plant operation or normal shutdown evolution resulting in a plant transient and challenge to control and safety systems. Based on its origin, an initiating event can be an internal or external event.

INSERVICE INSPECTION (ISI). An inspection performed after preservice inspections and test runs are satisfactorily completed and the system or component has been certified or accepted for normal service operation. The objective of such inspections is to detect degradation that might have occurred during plant operation.

INTERFACING SYSTEMS LOCA (ISLOCA). A breach in a system that interfaces with the reactor coolant system (RCS) and could cause a loss of coolant accident, if the breach is not isolated from the RCS. Such a breach could be caused if valves fail to isolate the RCS from an interfacing system not designed for the higher RCS pressure. When portions of an interfacing system are located outside the containment, ISLOCA can result in a radioactive release that bypasses the containment. Those ISLOCAs are referred to as a V-sequence.

INSPECTION LOCATION. An element in a risk-significant pipe segment and, therefore, a potential candidate for inspection.

INTERNAL EVENT. An event that initiates within plant systems and results in the perturbation of steady-state plant operation (e.g., loss of coolant, loss of heat sink, etc.).

LIKELIHOOD. Probability or frequency of an event. In this analysis, likelihood is defined as the expected frequency in events per unit time.

MITIGATING SYSTEM. Any plant system whose operation is required to mitigate consequences of an initiating event or plant transient. If one of the mitigating systems is disabled, remaining mitigating systems are referred to as backup systems.

PIPING COMPONENT. Piping or pipe fitting between adjacent welds.

PIPING SEGMENT. Continuous length of piping with the same degradation mechanism and failure consequence.

PIPING ELEMENT. A portion of a pipe segment. This portion might be a straight length of pipe, a weld, a pipe elbow, a fitting, a joint, etc., within the pipe segment.

PIPING SYSTEM. An assembly of piping segments. The system has defined functions, as described in the plant FSAR and controlled drawings. A piping system might include one or more ASME Code classes.

PRESSURE BOUNDARY FAILURE. Piping element failures involving ruptures or leakage that result in a reduction or loss of the element pressure-retaining capability.

PROBABILISTIC RISK ASSESSMENT (PRA). A quantitative assessment of risk. For nuclear power plant application, the risk is associated with plant operation and maintenance. Risk is measured in terms of the frequency of occurrence of various events, leading to a consequence of interest (e.g., core damage or release of radioactive material).

PROBABILISTIC SAFETY ASSESSMENT (PSA). See probabilistic risk assessment.

PROBABILITY. A numerical measure of the state of confidence about the outcome of an event.

RECOVERY ACTION. An operator action performed to mitigate or reduce the consequences of an event.

RISK. A measure of the potential for loss or damage. The risk of an event encompasses the expected frequency (the number of events per unit time) and expected damage (the magnitude of a consequence).

SPATIAL EFFECTS. The indirect impact of an event affecting other systems and components in the spatial vicinity. These effects include flooding, spray, pipe whip, jet impingement, etc.

V SEQUENCE. See interfacing system LOCA (ISLOCA).

ABOUT EPRI

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