Regulatory Analysis

Regulatory Approach for Steam Generator Tube Integrity

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PREFACE

The NRC staff initially concluded that a SG rule was the best regulatory approach for resolving difficulties with the current regulatory framework governing SG tube integrity. This report documents the regulatory analysis of the draft SG rule and associated draft RG that the staff developed in support of this effort. The results of the regulatory analysis caused the staff to re-evaluate whether a SG rule was the best regulatory solution from the available options. The staff subsequently decided that a generic letter approach was a more effective approach. As a result of this decision, additional resources to complete the regulatory analysis of the draft SG rule were not expended and as a consequence there are several sections of this report that are not completed. Additionally, for some portions of this report, the staff did not expend additional resources to revise the discussion to reflect the staff's decision to utilize a generic letter approach in lieu of a rule.

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EXECUTIVE SUMMARY

In pressurized water reactor (PWR) nuclear power plants, steam generator (SG) tubes are an integral part of the reactor coolant pressure boundary (RCPB) constituting a major part of the RCPB surface area (of the order of 50%). As such, SG tube integrity must be assured in order to maintain the primary reactor coolant inventory and pressure under a variety of operating conditions of normal operation including abnormal operating occurrences, design basis accidents, external events and natural phenomena. In addition, the tubes are relied upon to maintain their integrity consistent with containment objectives of preventing uncontrolled fission product release under conditions resulting from core damage severe accidents. In the framework of these considerations, operating experiences gained over the past 20 years, improved technology pertaining to SG tube integrity (such as non-destructive examination (NDE) testing), and better understanding of the various degradation mechanisms that affect SG tube integrity, have resulted in the need for improved and updated regulatory requirements applicable to SG tube integrity.

The criteria governing structural integrity of SG tubes were developed in the 1970s from assumptions relative to uniform tube-wall thinning. This led to the establishment of a 40 percent through-wall SG tube repair limit that has historically been incorporated into most PWR Technical Specifications (TS) and has been applied, in the absence of any other repair criteria, to all forms of SG tube degradation. Although the 40 percent through-wall depth criterion for SG tube repair is a good criterion for tube wastage, it is generally considered to be overly conservative (when growth rate and NDE uncertainties are properly considered) for many other forms of SG tube degradation mechanisms. The repair criteria do not allow licensees the flexibility to manage different types of SG tube degradation; licensees must either use the 40 percent through-wall repair criteria for all forms of degradation, or submit a plant-specific TS amendment for staff review and approval to enable the use of more appropriate repair criteria that consider the structural integrity implications of the given mechanism.

The existing TS do not explicitly require licensees to ensure that SG tube integrity is maintained for the planned operating cycle (i.e., determining flaw growth rates and NDE uncertainty to assess tube integrity at the end of the next planned operating cycle). Instead, existing TS indicate that SGs are operable when their tubes are repaired (i.e., it is implicitly assumed that the default 40% depth-based repair criterion and underlying assumptions concerning flaw growth rate and NDE uncertainty are sufficient to ensure end of cycle tube integrity, when in fact these assumptions may not be valid for the forms of degradation in the SGs).

The industry, through the Electric Power Research Institute (EPRI) Steam Generator Strategic Management Program Utility Steering Committee, proposed a generic approach referred to as "steam generator degradation-specific management" (SGDSM). Under this

approach, different methods of inspection and different repair criteria would be developed for different types of degradation. A degradation-specific approach to managing SG tube degradation would have several important benefits. These include: (1) improved scope and methods for SG inspections, (2) industry incentive to continue to improve inspection methods, and (3) development of plugging/repair criteria based on the most appropriate NDE parameters, thereby improving enforceability of the criteria and eliminating unnecessary conservatism. The NRC staff concluded that revising the existing regulatory framework to accommodate degradation-specific management the most appropriate course to address the issues of regulatory stability, resource expenditure, use of state-of-the-art in-service inspection techniques, repair criteria, and enforceability. The staff also concluded that an integrated approach for addressing SG tube integrity was essential and that materials, systems, and radiological issues that pertain to tube integrity needed to be considered in the development of the new regulatory framework.

As originally purposed, this report presented the results of a regulatory analysis for the staff's proposal to issue a new rule for addressing SG tube integrity. The regulatory analysis is based on "Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission," NUREG/BR-0058, dated November 1995. The report was subsequently modified, in part, to provide the basis for the staff's decision to revise its initial regulatory approach of issuing a rule to ultimately utilize a generic letter approach instead.

This regulatory analysis incorporates the staff's justification for invoking the 10 CFR 50.109(a)(4)(i) compliance exception provision for the additional requirements involving the inspection, monitoring, and assessment of SG tube condition. The staff concludes that the additional requirements are necessary to ensure that tube integrity is maintained for the planned operating cycle consistent with applicable regulations and the plant's licensing basis. The staff's compliance exception justification is contained in Section 1.2 and was drafted to support incorporation of the additional requirements into the draft rule. Section 1.2 has not been re-written to reflect the generic letter approach. However, the same arguments apply for imposing the new requirements through the use of a generic letter.

The draft SG rule was a performance-based, risk-informed approach that required SG tubes to be monitored and maintained against performance criteria such that there is reasonable assurance the tubing will remain capable of performing their intended safety functions. Given the performance-based structure to the draft rule, the staff had to make assumptions as to what specific actions would be required by Pressurized Water Reactor (PWR) licensees for compliance with the draft rule's requirements. The regulatory analysis utilized draft Regulatory Guide (RG) X.XX "Steam Generator Tube Integrity" as a reasonable approximation of the additional actions that would be necessary for compliance with the draft SG rule.

The draft SG rule as a whole was assessed from a value-impact perspective (i.e., per 10 CFR 50.109(a)(3)) recognizing that the staff had concluded that all the additional

requirements, with the exception of those pertaining to the risk resulting from severe accident induced SG tube rupture, appeared to be supportable based on a compliance exception approach. This perspective was pursued for two basic reasons:

(1) It provides an overall understanding of the draft rule's net value, and this information, particularly the risk reduction and implementation costs, is useful in supporting the review of the Committee for Review of Generic Requirements (CRGR).

(2) The risk reduction portion that applies only to the risk requirements of the draft rule could be readily separated and examined on its own merits.

The important assumptions for the draft SG rule value impact assessment are:

(1) Of the 73 PWRs considered, 10 were assumed to be "high risk" while the remaining 63 PWRs were assumed to have "representative risk."

(2) Risk reduction from rule implementation (the "avoided risk") results only from one category of steam generator tube ruptures (SGTRs), namely the temperature-induced (severe accident-induced) SGTRs. It is assumed that there would be no risk reduction due to the draft SG rule from the other categories of SGTRs, namely the spontaneous SGTRs and the pressure-induced (e.g., rapid secondary system depressurizations from main steam line breaks) SGTRs.

(3) The core damage frequency (CDF) for the Base Case (i.e., the currently existing situation) is 3.1E-5/r-yr while the corresponding large early release is 1.3E-5/r-yr. The CDF of 3.1E-5/r-yr was chosen as a representative of the Probabilistic Risk Assessment (PRA) results to date for core damage events that result from spontaneous SGTR, pressure-induced SGTR and temperature-induced (severe accident-induced) SGTR. It was further assumed that, except for the temperature-induced (severe accident-induced) SGTR, all the other SGTR core damage categories result in direct releases into the environment; i.e., bypass the containment barrier and result (with an assumed conditional probability of 1) in a stuck open secondary system safety or dump valve. For the temperature-induced SGTRs, an accident progression event tree (APE) was developed to assess the early large release fraction.

(4) From the sensitivities performed, it was assumed that the draft SG rule would result in a reduction in Large Early Release Frequency (LERF) of 8×10^{-6}/r-yr or about one order of magnitude.

(5) Two variants of the rule are considered: one that is performance-based (i.e. no technical specifications (TS)) and one that is more prescriptive and is TS-based (i.e., the draft RG is required as part of TS).

The Net Value of the SG rule implementation considering all rule costs and all rule risk reductions is -\$350 M for the performance-based rule variant and is -\$460 M for the TS-based rule variant. Thus, under the assumptions made in this analysis, the rule, as a whole, can not be justified from a cost-benefit or value-impact point of view. Since all the additional SG requirements, with the exception of the requirements related to severe accident-induced SGTR, are supported with a compliance exception justification per 50.109 (a)(4)(i), the Net Value does not have to be positive to allow for advancing the rulemaking process.

Of the seven attributes that make up the Net Value equation

$$NV = V_1 + V_2 + V_3 + V_4 + V_5 - (I_1 + I_2)$$

the major contributor to the net "negative" finding is the Impact (I2) or cost to the industry of +\$400 M for the performance-based rule variant and +\$500 M for the TS-based rule variant. The key contributors to this high industry cost are the continuous costs from altered inspection cycles, the continuous costs of increased tube inspections, and the one-time costs associated with primary-to-secondary leakage monitoring hardware installation. Counteracting a portion of these industry impacts was the large negative cost (benefit to industry) of avoided unplanned shutdowns.

To examine these results further, an additional case which looked at the cost impact that considers what licensees are currently doing on a voluntary basis was examined. This "Voluntary Actions" case was added to the Net Value analysis as a sensitivity study to examine the impact of voluntary actions that the industry has taken to reduce the likelihood of SGTR. Thus the "Voluntary Actions" case Net Value reflects the Impacts in going from the status quo (with the voluntary actions in place) to the Rule Case. The original Net Value analysis did not allow for any "voluntary actions" in the Base Case -- as per guidance from the NUREG/BR-0058. Thus the "Base Case" Net Value reflects the Impacts in going from a situation where only NRC-mandated conditions on the SGs are in place (i.e., assuming no voluntary actions are in place) to the Rule Case. The Industry-Impact value drops considerably when considering the Voluntary Actions ("VA") Case (from about \$500M to \$140M) thus showing that the industry has already invested about \$500M minus \$140M or \$360M in SG-related improvements. In addition to the Voluntary-Actions Case shedding light on the impact of industry actions to date, it also allows for a more consistent Net Value assessment, in that the "Value" portion (elements V1, V2, V3, & V4) of the Net Value equation, which was not changed for this voluntary-action sensitivity study, represents the risk avoided in going from the status quo (which includes "voluntary actions") to the rule implementation.

To examine whether the severe accident-induced SGTR related requirements of the SG rule could be separately supported (i.e., these requirements could not be supported as meeting a 50.109(a)(4) backfit exception provision) on a value-impact basis per 50.109(a)(3), the

values and impacts for this portion of the rule were examined separately. The only cost included in this assessment is the cost of performing a risk assessment. This cost is estimated at $100,000 per plant for performing the risk assessment and $15,000 for each NRC review. Most importantly, because time constraints precluded incorporation, the costs associated with actually achieving the assumed risk reduction are not included. Since as has been previously mentioned, there was no assumed reduction in risk for either spontaneous SGTRs or pressure-induced SGTRs, this separate examination of risk requirements is credited with achieving the entire assumed risk reduction. The net value for just the risk requirements portion of the SG rule would be approximately +$700,000 per plant without including the costs to the plant to achieve the assumed risk reduction. Given the assumptions that led to this net value result which maximized the assumed risk reduction (i.e. assumed largest risk reduction from the sensitivities performed, assumption that 10 plants were high risk) and giving consideration to the level of costs that would be incurred to achieve the risk reductions (i.e., plant modifications, plant procedure changes, supporting analysis, operator training), the staff concluded that a more refined estimate of the net value for this portion of the draft rule would probably result in either a very small positive net value or more likely a negative net value. As such, additional requirements for licensees to take actions in order to reduce risk could not be justified on a generic basis as either satisfying the 10 CFR 50.109(a)(4) backfit exception or meeting the 10 CFR 50.109(a)(3) criteria.

Given the two major conclusions discussed above that (1) additional risk reduction requirements could not be imposed on PWR licensees on a generic basis (as long as those licensees are not relaxing current tube integrity criteria) and that (2) additional requirements for inspecting, monitoring and assessing SG tube condition, and maintaining SG tube integrity for the planned operating cycle are necessary and should be pursued as compliance backfits to existing regulations in accordance with 10 CFR 50.109(a)(4)(i), the staff reassessed whether a rule was the appropriate regulatory vehicle for addressing the problems associated with SG tube integrity. The staff noted that a fundamental basis for invoking the compliance provision of 50.109 for the additional inspection, monitoring and assessment requirements was that the governing regulations were adequate for ensuring SG tube integrity, but that the implementation of those regulations via the TS was deficient. Resolution of this type of problem (i.e., fixing TS) is amenable to a generic letter approach. Additionally, the staff noted that although risk reduction requirements could not be generically imposed on PWR licensees, licensees who proposed alternate criteria would need to address risk considerations since the staff's technical work did indicate the possibility that risk could increase under such circumstances. This situation could also be addressed with a generic letter that provides guidance to licensees on what needs to be considered when pursuing alternate SG tube repair criteria. Given all these considerations, the staff concluded that promulgation of a new rule was neither necessary nor appropriate since the governing regulatory framework was adequate, and that the problems with the current regulatory framework could be addressed with a generic letter approach that could achieve the objectives originally established for the SG rule.

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APPENDICES:

Note: Appendices B&C are not used at this time

ACRONYMS

ADV	Atmospheric Dump Valve
ANO	Arkansas Nuclear One
ARC	Alternate Repair Criteria
ASME	American Society of Mechanical Engineers
B&W	Babcock And Wilcox
CDF	Core Damage Frequency
CE	Combustion Engineering
CRGR	Committee for Review of Generic Requirements, Dated 12/11/95
EAB	Exclusion Area Boundary
ECT	Eddy Current Testing
EDM	Electric Discharge Machining
EPRI	Electric Power Research Institute
GDC	General Design Criteria (or Criterion)
GL	Generic Letter
I	Impact (In Net Value Formulation)
IGSSC	Intergranular Stress Corrosion Cracking
IPE	Individual Plant Evaluations
LCO	Limiting Conditions for Operation
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LPZ	Low Population Zone
MSLB	Main Steam Line Break
MSSV	Main Steam Safety Valve
NDE	Non-Destructive Examination
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
NV	Net Value
ODSCC	Outside Diameter Stress Corrosion Cracking
PDS	Plant Damage State
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Assessment
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RA	Regulatory Analysis
RC1	Large Release Frequency
RCP	Reactor Coolant Pump
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
RG	Regulatory Guide
RG X.XX	Steam Generator Tube Integrity Draft Regulatory Guide

SBO	Station Blackout
SCC	Stress Corrosion Cracking
SG	Steam Generator
SGDSM	Steam Generator Degradation Specific Management
SGTR	Steam Generator Tube Rupture
SORV	Stuck Open Relief Valve
SRP	Standard Review Plan
SRV	Safety Relief Valve
SSC	Structures, Systems, and Components
Sv	Sieverts
SV	Safety Valve
TS	Technical Specification(s)
TSP	Tube Support Plate
V	Value (In Net Value Formulation)
W	Westinghouse

1. Statement of Problem and Objective

This report is formatted as a Regulatory Analysis based upon the guidelines given in NUREG/BR-0058, "Regulatory Analysis Guidelines of the U. S. Nuclear Regulatory Commission," Revision 2, dated November 1995. The purpose of the report is to provide a basis for the proposed action involving steam generator (SG) tube integrity to enable the staff and the Commission to determine whether adequate justification for the proposed action has been provided. Accordingly, the framework of this report sets forth (1) identification of the problems and associated objectives, (2) identification of alternatives for meeting the objectives, (3) an analysis of the consequences of alternatives, (4) selection of preferred alternatives, and (5) documentation of the analysis.

SG tube surveillance and maintenance continue to be a problem both for the industry and the NRC staff because of the following:

- The existing technical specifications (TS) are based upon the premise that wastage (thinning of tube walls) is the primary degradation mechanism affecting tube integrity. However, other important degradation mechanisms are not effectively addressed by the wastage tube repair limit.

- The existing TS do not explicitly require licensees to ensure that SG tube integrity is maintained for the planned operating cycle (i.e., determining flaw growth rates and NDE uncertainty to assess tube integrity at the end of the next planned operating cycle). Instead, existing TS indicate that SGs are operable when their tubes are repaired (i.e., it is implicitly assumed that the default 40% depth-based repair criterion and underlying assumptions concerning flaw growth rate and NDE uncertainty are sufficient to ensure end of cycle tube integrity, when in fact these assumptions may not be valid for the forms of degradation in the SGs).

- Nondestructive Examination (NDE) SG tube inspection techniques, findings, and corrective action criteria (such as depth-based repair criteria) are based on this outdated degradation premise. As a result, without TS changes, licensees are not permitted the flexibility to manage different types of tube degradation that commonly occur. Licenses can only use NDE techniques that are qualified for the degradation being inspected. However, currently there is no qualified NDE technique for sizing length and depth of intergranular stress corrosion cracking (IGSCC). In the absence of qualified NDE techniques, licensees must repair certain forms of SG tube degradation upon detection. Therefore, licensees must submit plant-specific TS amendments to enable the use of alternate repair criteria (ARC) that consider the structural integrity implications of a given degradation mechanism (e.g., Generic Letter (GL) -95-03, "Circumferential Cracking of SG Tubes," and GL-95-05).

- The overall result of a plant-specific review approach is increased regulatory uncertainty and resource expenditure.

The proposed SG tube integrity rule was to have permitted a performance-based approach to SG tube surveillance and maintenance. The proposed rule specifies that the performance criteria consist of three parts: (1) tube structural integrity; (2) accident-induced leakage integrity; and, (3) operational leakage integrity. Its adoption will eliminate the expenditures relative to continuing with current practice -- a case-by-case review and licensing amendment strategy -- and will ensure that a consistent and stable set of updated requirements are put in place to generically cover the actual SG tube degradation mechanisms currently being experienced and to more effectively monitor developing primary-to-secondary leakage.

Although the staff concludes that the public health and safety have been adequately protected under the current approach of specifying prescriptive surveillance and tube repair criteria in TS, substantial clarification and improvement to the regulatory framework is warranted to ensure licensee compliance with the Commission's requirements.

In addition, the staff has given consideration to severe accidents and the role that SG tubes play in the overall defense-in-depth framework of safety. A major focus of this regulatory analysis is on accidents that result in core damage, that is, severe accidents that release radionuclides into the environment. Steam Generator Tube Ruptures (SGTRs), occurring spontaneously or caused by large differential pressures across the tubes, can cause core damage (and resulting severe accidents) if safety systems and associated operator actions fail to mitigate the consequences of the tube ruptures. In addition, there is a class of accidents considered in this regulatory analysis that is characterized by severe core-damage accidents causing previously intact SG tubes to fail after core damage has occurred. This latter class of accidents is referred to as severe accident induced tube rupture (or failure). Added importance is given to SG-related severe accidents because of defense-in-depth considerations, that is, all SGTRs bypass the most important defense-in-depth structure, namely the containment with its associated accident mitigation systems. When secondary-side dump or safety valves are open, there is a direct release to the environment.

The objective of the proposed rule would be to: (1) ensure that SG tubes can perform their safety function and that there is an extremely low probability of excessive SG tube leakage, which could cause core damage or exceed allowable offsite doses, and (2) allow a reasonable approach to SG surveillance and maintenance activities (i.e., degradation-specific management). A central objective of the proposed rule is to permit flexibility in the surveillance and maintenance of SG tubes, thereby encouraging the use of state-of-the-art SG tube inspection and analysis techniques and substantially reducing the regulatory effort required of industry and the NRC staff in ensuring the integrity of SG tubes assuring that their safety function would be maintained.

1.1 Background of the Problem

There are currently 73 pressurized water reactor (PWR) power plants operating in the United States (51 W; 15 CE; and, 7 B&W NSSS vendors). The number of steam generators (SG)

in each plant vary depending upon the particular nuclear steam system supplier (NSSS) vendor and plant size. In all, there are 227 SG in operation at these plants based upon data derived from Electric Power Research Institute (EPRI). Adding up the number of SG tubes results in a total of approximately 1.4 million tubes that are in operation at these plants.

In addition to the attendant safety concerns that pertain to SG tube integrity, successful management of SG operational issues is essential to minimize forced plant outages that lead to costly loss of production. One real incentive for improving SG tube integrity is better assurance for increased electrical generation. Thus, the incentive for improved SG tube performance leads to benefits that are both economical as well as safe.

The heat transfer area of PWR SG can comprise 50 percent of the area of the total primary system pressure-retaining boundary. Thus, the SG tubing is an important part of the barrier against fission product release to the environment since the tubes function as both the reactor coolant pressure boundary and as part of the containment boundary for core damage events.

To remain an effective barrier, manufacturing defects and service-induced degradation of SG tubing must be minimized. Periodic in-service inspection of SG tubing, as required by 10 CFR 50 Appendix A, General Design Criteria (GDC) and 10 CFR Part 50.55a, are essential elements of the overall defense-in-depth concept for maintaining and assuring primary system integrity.

1.1.1 History of the Problem

SG tube degradation at nuclear power plants continues to be a problem for the nuclear industry. Industry actions have been effective in controlling many forms of degradation experienced in the late 1970s and early 1980s. However new degradation mechanisms continue to occur (see Figure 1; TR-106365). In the early to mid 1970s, when plants typically operated under a phosphate water chemistry program, wastage was the dominant degradation mechanism. Under this type of degradation mechanism, the metal on the surface of the tube is uniformly removed due to corrosion. This type of wastage or thinning of the tube is readily detected by eddy current testing, and the degradation can be easily identified and monitored. To minimize the potential for tube wastage the majority of PWRs converted to an all-volatile treatment of secondary-side water; this change eliminated the problem with tube wastage.

As tube wastage was eliminated, tube denting became a prominent degradation mechanism. Denting results from the corrosion of carbon steel support structures such as tube support plates. Environmental factors that contribute to the corrosion of these support structures include high chloride concentrations and the presence of oxygen or copper, which act as oxidizing agents. These corrosion products, which occupy about twice the volume of the original structure, impact the tubes and cause high stresses in the tubes and surrounding structure. The mechanical damage to the tube has in some instances resulted in the development of stress-corrosion cracking (SCC). Measures such as reducing chloride levels

and reducing oxidizing potential have been successful in controlling denting. Minor denting continues and, in some cases, primary water stress corrosion cracking (PWSCC) is associated with it. However, SCC not associated with denting has become the dominant degradation mechanism.

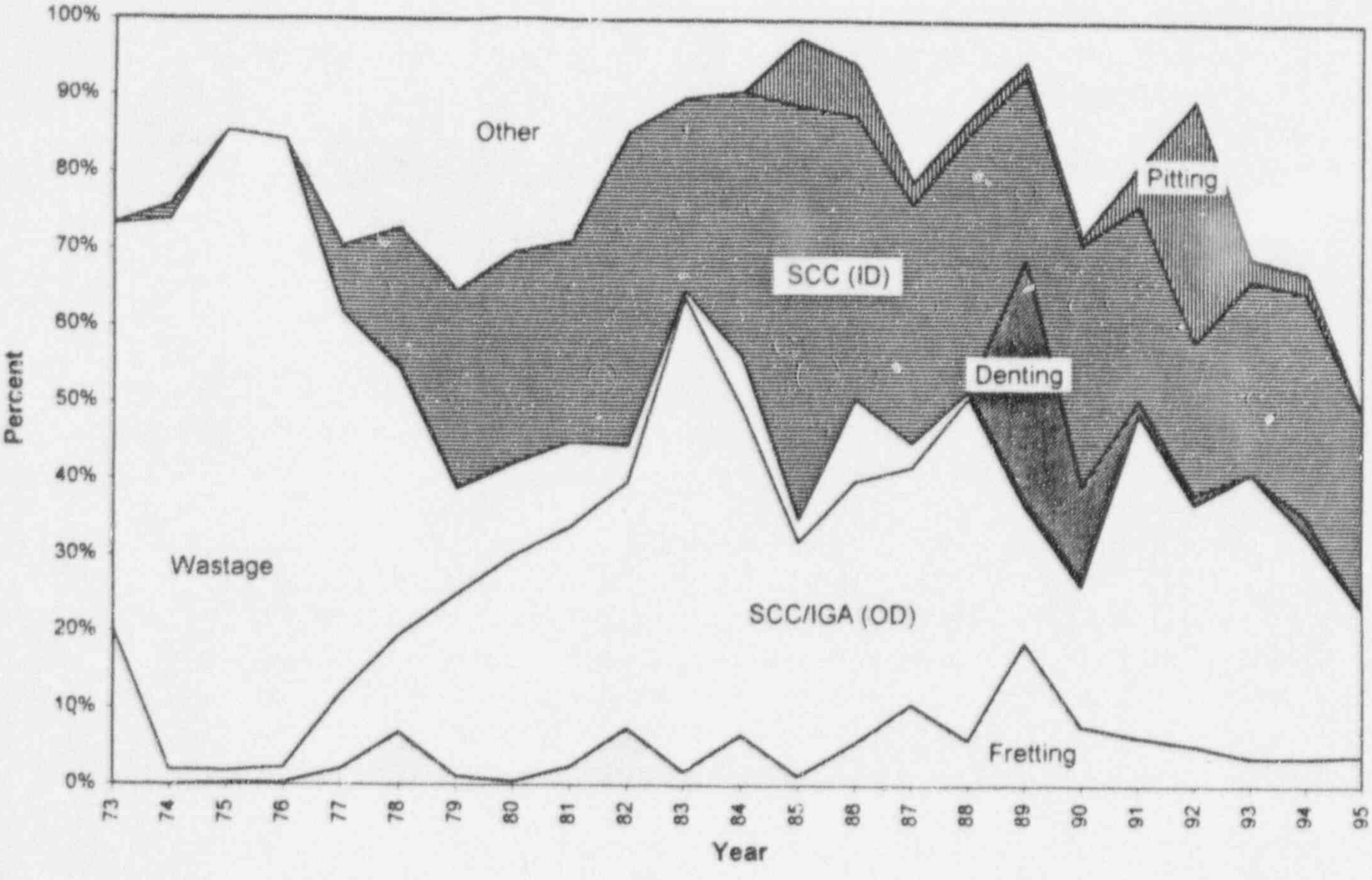


Figure 1 - 1 United States Causes of Steam Generator Plugging

Since 1980, SCC mechanisms have emerged as the dominant degradation mechanism affecting SG tubing. They have been observed to begin from both the inside and the outside of the tube. Two predominant types of SCC are (1) PWSCC that occurs on the inside diameter of the tube at the expansion-transition location where the diameter changes as a result of the tube's expansion into the tube sheet; and, (2) outside diameter stress-corrosion cracking (ODSCC) that occurs on the outside diameter of the tube in the tube support plate region.

There have been seven steam generator tube rupture (SGTR) events that have occurred during plant operations in the United States. Each of these events involved a single tube failure. The failure mechanisms of these events are summarized in the following paragraphs:

Point Beach, Unit 1 - A SGTR occurred on February 26, 1975 and is believed to have occurred after a crack had penetrated entirely through the tube wall and had grown sufficiently long to permit bursting. The flaw is believed to have initiated at a high growth rate in September 1974 during on-line conversion from phosphate to all-volatile treatment secondary water chemistry.

Surry, Unit 2 - A SGTR occurred on September 15, 1976 as a result of SCC in the U-bend. Subsequent investigation revealed cracks in other tubes.

Prairie Island, Unit 1 - A SGTR occurred on October 2, 1979. It was the result of excessive wear caused by a foreign object rubbing against the tube.

R. E. Ginna Nuclear Power Plant - A SGTR occurred on January 25, 1982 was caused by impingement damage induced by a foreign object and by the breakage of previously plugged tubes with adjacently plugged and unplugged tubes.

North Anna, Unit 1 - The unit experienced a SGTR at the top of the seventh support plate in the cold leg on July 15, 1987. The failure mechanism associated with the rupture involved rapid crack propagation. Based on the available information, the NRC staff concluded that the presence of all of the following requisite conditions could lead to a rapidly propagating fatigue failure such as that which occurred at North Anna: (1) denting at the upper support plate; and (2) fluid-elastic stability ratio approaching that for the tube that ruptured; and (3) absence of effective anti-vibration support.

McGuire, Unit 2 - The unit experienced a SGTR on March 17, 1989. The unit was at 83% power when a single tube ruptured in the "B" SG. The region where the defective tube was located had been tested during preservice inspection, but not afterwards. The rupture resulted from a free span axially oriented crack. The crack was approximately 3.48-inches long and 0.2-inches wide at the maximum rupture opening.

Palo Verde, Unit 2 - On March 14, 1993, while operating at 98% power, the unit experienced a SGTR in SG-2. The ruptured tube was found to be defective during an

inspection in November 1991, and a decision was made at that time to plug the defective tube. Consequently, it was decided to install mechanical plugs on the cold leg and hot leg sides of the defective tube. However, due to installation and verification errors the tube was not plugged on its hot leg end.

As a result of improved technology (e.g., nondestructive testing, data acquisition capability), changes in degradation mechanisms and operating experience gained in the last 20 years, the current regulatory criteria have become outdated and in some cases ineffective. The criteria governing SG tube structural integrity were developed in the 1970s and were derived from the assumptions relative to uniform wall thinning. The resultant 40-percent through-wall SG repair tube limit has been typically incorporated into plant TS (some plants, e.g., Callaway, have different repair limits) and has been applied, in the absence of any other repair criteria, for all forms of SG tube degradation.

Although the 40-percent through-wall depth criterion for SG tube repair is suitable for tube wastage, it is generally overly conservative for some forms of SG tube degradation. Currently, SCC initiated on either the inside or the outside of the tube wall is the degradation mechanism of most concern. For this mechanism, it is difficult for commonly used eddy-current techniques to reliably identify cracks until they are 40-percent through-wall depth. Furthermore, for certain locations and crack mechanisms, such as ODSCC at the tube support plate (TSP) intersections or PWSCC at the rolled transition area, a crack depth limit is not regarded as an appropriate repair criterion. Operating experience and research show that the burst strength of tubes is very sensitive to crack length as well as to depth. As a result, the current 40-percent through-wall limit incorporated in current TS can neither be practically implemented nor complied with, and licensees are generally forced to plug or sleeve tubes as soon as cracks are detected. For these reasons, the 40-percent through-wall criterion is not appropriate for the dominant degradation mechanisms affecting SGs today.

In addition, the current criteria do not allow licensees the flexibility to manage different types of SG tube degradation. Licensees must either use the 40-percent through-wall repair criteria for all forms of degradation or must submit a plant-specific TS amendment for staff approval to enable the use of more appropriate repair criteria that consider the structural integrity implications of the given mechanism. These issues have been addressed by the staff in recent generic letters such as GL 95-03 and GL 95-05).

1.1.2 Other Considerations

The staff has prepared a draft Regulatory Guide (RG) that describes an acceptable basis for complying with the requirements of a new proposed rule pertaining to SG tube integrity. This guide would supersede the guidance given in NRC RG 1.83 and supplements the guidance given in RG 1.121. The guide contains performance criteria that pertain to SG tube integrity, inspection, repair criteria, primary-to-secondary system leakage limits and monitoring, and radiological aspects of SG tube failure. These aspects have been included in this regulatory analysis as they concern the impact of adopting the proposed SG integrity rule.

To date, the staff has processed several plant-specific TS amendments for the use of alternate SG tube repair criteria. For example, more than six plants have received staff approval to use alternate repair criteria on a cycle-to-cycle basis for ODSCC at the intersections of the tubes and the tube support plate (TSP). This approach can lead to inconsistencies between reviews and inhibit the development of generic criteria because such large staff resources are needed for the review and approval of plant-specific submittals. The overall result of a case-specific review approach is increased regulatory uncertainty and resource expenditure. In the case of ODSCC, GL 95-05 provided guidance on voltage-based repair criteria for Westinghouse SGs. This allows licensees to voluntarily initiate a program and propose permanent TS amendments to address axially-oriented ODSCC indications located at the tube-to-TSP intersections as a specific type of degradation. EPRI has indicated the possibility that a significant number of additional licensees would be interested in pursuing alternate repair criteria. Hence, unless the staff implements a flexible regulatory framework in which the industry is permitted to develop programs that satisfy the rule's performance criteria, there is a strong likelihood that inconsistencies between reviews will continue to occur and the impact on staff resources could get significantly worse.

In another area related to SG tube integrity, there are concerns that the calculated radiological consequences of a postulated tube rupture based upon Standard Review Plan (SRP) (NUREG-0800) Chapter 15 assumptions can be overly conservative and limiting. TS limits are established on the activity levels (such as I^{131}) in the reactor coolant to ensure that in the unlikely event of a SGTR, the offsite exposure would not exceed current Part 100 guidelines. In addition, the dose to control room personnel would also not exceed the guidelines defined more extensively in SRP Section 6.4 per General Design Criteria (GDC) 19.

The staff is also proposing to provide greater flexibility to licensees to leave certain degraded SG tube in operation without subjecting the tubes to immediate repair (such as plugging or sleeving) by lowering the allowable activity limits in accord with SG tube leakage rates. In such instances, licensees would be required to assess whether allowing such tubes to remain in service is based upon a conditional assessment and the considerations that can result in a new or different accident from those previously analyzed (i.e., 10 CFR 50.59). The effect of degradation in this regard was included in this regulatory analysis with regard to an impact.

In another area, no uniform and systematic requirements currently exist for instrumentation that monitors SG primary-to-secondary leakage. Such monitoring instrumentation is in use on some plants and has improved the monitoring capability significantly in recent years. However, TS do not include LCO and surveillance requirements for this instrumentation. In addition, leakage limits vary among the TS. RG X.XX provides for operational monitoring of primary-to secondary leakage that would provide for appropriate and timely action before SG tube leakage exceeds the tube integrity performance criteria. The RG addresses the development of monitoring programs and allowable limits for operational leakage. These aspects have been included in the overall rule assessment program.

1.1.3 The Relationship of the Problem to Other Ongoing Studies or Actions

Maintenance Rule - The question was raised by NEI and others as to whether SG tube integrity matters could be included in the framework of the maintenance rule; i.e., 10 CFR 50.65 - Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants. The argument is predicated on the premise that the maintenance rule and the proposed SG tube integrity rule are both performance-based. In addition, the SG tubes are part of the reactor coolant pressure boundary, and therefore, fall in the category of what are considered to be safety-related structures, systems, and components (SSC) covered in the maintenance rule. Considerations pertaining to the basis for issuing a separate and new SG tube integrity rule are fully addressed in Section 2.2.6 of this Regulatory Analysis.

Industry efforts to address SG tube degradation concerns - The industry, through the EPRI Steam Generator Strategic Management Program Utility Steering Committee, has proposed a generic approach referred to as "steam generator degradation-specific management" (SGDSM). Using this approach, different methods of inspection and different repair criteria would be developed for different types of degradation. The proposal was made to the NRC in four topical reports on (1) overall criteria to be satisfied by any tube repair criteria, (2) in-service inspection guidelines, (3) voltage-based repair criteria for ODSCC, and (4) length-based repair criteria for PWSCC in roll-transition region. The NRC concluded that the SGDSM approach had several important benefits. These include (1) improved scope and methods for SG inspections, (2) industry incentive to continue to improve inspection methods, and (3) development of plugging/repair criteria based on the most appropriate NDE standards, thereby improving enforceability of criteria and eliminating unnecessary conservatism. Codifying such a generic approach for managing SG tube degradation through rulemaking was judged to be the most appropriate course to address the issues of regulatory stability, resource expenditure, use of state-of-the-art in-service inspection techniques, out-of-date repair criteria, and enforceability.

1.1.4 The Objectives of the Proposed Action and the Relationship of the Objective to NRC's Legislative Mandates, Safety Goals for Maintenance and Operation of Nuclear Power Plants and Policy and Planning Guidance

The objective of the proposed rule would be to provide for the development of a program that monitors the condition of SG tubes against performance criteria in a manner sufficient to provide reasonable assurance that the SG tubes remain capable of fulfilling their intended safety functions and that adequate protection to the health and safety of the public is maintained.

The NRC's five year plan states that part of the NRC's legislative mandate"... is to ensure adequate protection of the public health and safety...." Identified overall agency goals are as follows:

o Ensure that licensees operate nuclear power plants safely, are adequately prepared to respond properly to events and accidents, and implement regulatory initiatives to correct design and operational inadequacies.

o Ensure that the NRC is prepared to deal with severe accident issues at operating reactors.

o Ensure that the combination of industry and NRC research provides the technical bases for timely and sound rulemaking and regulatory decisions in support of NRC licensing and inspection activities.

o Allocate NRC's human and capital resources and direct the agency's affairs so that they contribute most effectively to the mission of protecting public health and safety.

Selected aspects of the Five-Year Plan's Reactor Program Objectives and Guidance include (among others) the following:

"1d. The NRC will take plant-specific actions, consistent with the backfit rule."

"25c. The NRC will, to the extent practicable, resolve issues that affect numerous licensees either by rule or generic reviews."

1.1.5 Constraints or Other Cumulative Impacts that Work Against Solutions to the Problem

No constraints or cumulative impacts exist that are preventing a solution to the problem.

1.1.6 Draft Papers or Other Underlying Staff Documents Supporting the Requirements or Staff Positions

Draft NUREG-1570, "A Risk Assessment of Steam Generator Tube Rupture Induced by Severe Accidents," [To Be Published]

Draft Regulation Guide DG-1061, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decision on Plant Specific Changes to the Current Licensing Bases"

INEL-95/0641, "Steam Generator Tube Rupture Induced from Operational Transients, Design Basis Accidents, and Severe Accidents," August 1996

Draft Proposed Rule - "Steam Generator Rule," (Revision 11.6), November 5, 1996

Draft Proposed Regulatory Guide X.XX, "Steam Generator Tube Integrity," November 5, 1996

Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," Revision 1, July 1975

Regulatory Guide 1.121, "Bases for Plugging Degraded Steam Generator Tubes," August 1976

Generic Letter 95-03, "Circumferential Cracking of SG Tubes," April 28, 1995

Generic Letter 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking," August 3, 1995

NRC Information Notice 94-43, "Determination of Primary-to-Secondary Steam Generator Leak Rate," June 10, 1994

NRC Information Notice 94-05, "Potential Failure of Steam Generator Tubes with Kinetically Welded Sleeves, " January 19, 1994

NRC Information Notice 93-56, "Weaknesses in emergency Operating Procedures Found as a Result of Steam Generator Tube Rupture," July 22, 1993

NRC Information Notice 92-80, "Operation with Steam Generator Tubes Seriously Degraded," December 7, 1992

NRC Information Notice 91-43, "Recent Incidents Involving Rapid Increases in Primary-to-Secondary Leak Rate," July 5, 1991

NRC Information Notice 91-67, "Problems with the Reliable Detection of Intergranular Attack (IGA) of Steam Generator Tubing," October 21, 1991

NRC Information Notice 90-49, "Stress Corrosion Cracking in PWR Steam Generator Tubes," August 6, 1990

NRC Information Notice 88-99, "Detection and Monitoring of Sudden and/or Rapidly Increasing Primary-to-Secondary Leakage," December 20, 1988

NRC Bulletin No. 88-02, "Rapidly Propagating Fatigue in Steam Generator Tubes," February 5, 1988

NUREG-0844; "NRC Integrated Program for Resolution of Unresolved Safety Issues, A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity," September 1988

NUREG-1150, "Severe Accident Risks: An Assessment for Five U. S. Nuclear Power Plants," December 1990

NUREG-1140, "Loss of Vital AC Power and the Residual Heat Removal System During Mid-Loop Operations at Vogtle Unit 1 on March 20, 1990," June 1990

NUREG/CR-4627, "Generic Cost Estimates," Revision 1, February 1989

NUREG/CR-2723, "Estimates of the Financial Consequences of Nuclear Power Reactor Accidents," November 1982

NUREG/CR-2239, "Technical Guidance for Siting Criteria Development," December 1982

NUREG/BR-0058, "Regulatory Analysis Guidelines of the U. S. Nuclear Regulatory Commission," Revision 2, November 1995

INEL Draft Letter Report DWA-47-94, "Primary-to-Secondary Leak Rate Monitor Project Draft Report," November 1994

EPRI-TR-106365, "Steam Generator Progress Report, Revision 12," October 1996

EPRI-TR-104788, "PWR Primary-to-Secondary Leak Guidelines," May 1995

EPRI-NT-6201, "EPRI Steam Generator Examination Guidelines," Revision 3; 1992

ASME Section XI; Appendix VIII

ASNT SNT-TC 1A; Recommended Practice; 1992

Advanced Manual for Eddy Current Test Methods; Canadian General Board; 1986

Parts 1 and 2 of 1994 Workshop on PWSCC of Alloy 600 in PWRs; 1995

Draft Report from GEBCO Engineering on Survey of PWR Plants on Primary-to-Secondary Leakage Monitoring; 11/96

1.2 Backfit Considerations for the Steam Generator Tube Integrity Rule

The following compliance exception justification was drafted to support incorporation of the additional requirements into the draft SG rule and has not been re-written to reflect the revised regulatory approach of using a generic letter. However, the same arguments apply for imposing the new requirements within the draft SG rule framework as those that apply for use of a generic letter (that requests PWR licensees to revise their TS). In fact, part of the reason for the staff's decision to revise the regulatory approach stems from the fact that a fundamental basis for invoking the compliance provision of 50.109 for the additional inspection, monitoring and assessment requirements was that the governing regulations were adequate for ensuring SG tube integrity, but that the implementation of those regulations via the TS was the problem. Resolution of this type of problem is amenable to a generic letter approach and does not require promulgation of a rule.

1.2.1 Introduction

There are basically three options for addressing new requirements within the SG rule:

1. Justify the imposition of the new requirements as a backfit exception via 10 CFR 50.109 (a)(4):

(i) compliance exception
(ii) adequate protection exception
(iii) redefining/defining adequate protection

For this option, it is not necessary to perform the value/impact backfit analysis and instead it is only necessary to provide a justification for invoking the 50.109 exception criteria.

2. Justify imposition of the new requirements via a value/impact backfit analysis via 50.109 (a)(3). For this approach, it is necessary to (1) show there is a substantial increase in the overall protection of the public health and safety and (2) show that the direct and indirect costs of implementation are justified in view of this increased protection.

3. Make the requirement voluntary in which case no requirement is being imposed and therefore there is no backfit consideration.

It should be recognized that "relaxations" are not considered to be "backfits" since the staff is not imposing more restrictive requirements on licensees and is instead relaxing current

requirements. However, "relaxations" need to be considered in the regulatory analysis to ensure that "adequate protection" to the health and safety of the public is maintained.

1.2.2 Backfit Justification

The discussion that follows provides the justification for invoking the compliance backfit exception provisions of 50.109(a)(4)(i) to impose the proposed SG rule with the exception of risk aspects.

1.2.3 Proposed Rule Objective

The current regulations of 10 CFR 50 Appendix A GDC [GDC 1,2,4,14,30,31,32], the ASME Code (via 10CFR 50.55a reference), and the licensee TS recognize the importance of the SG tubes as functioning both as part of the reactor coolant pressure boundary and as part of the containment barrier. SG tubing as part of the reactor coolant pressure boundary is required to be designed as a safety class 1 component and as such the tubes must be capable of performing their intended safety functions under the postulated design basis conditions. The proposed SG rule's objective is to ensure that the aforementioned requirements continue to be met through the implementation of a new performance-based regulatory framework. In this regard, the proposed rule is consistent with current regulations and is not imposing a more restrictive overall standard.

1.2.4 Background/Revised Regulatory Framework

To ensure adequate tube integrity consistent with 10 CFR 50 Appendix A, the plant TS require periodic inservice inspection of the SG tubing at specified frequencies and using specified tube inspection sampling plans. The TS require that tubes found by inspection to contain flaws exceeding the tube repair criteria be removed from service by plugging or repair. The inspection methods (i.e., equipment, procedures, personnel qualifications) are subject to the requirements of 10 CFR 50 Appendix B and the ASME Code, Section XI. The TS also specify limits on allowable primary-to-secondary leakage beyond which the SGs must be shutdown and an inservice inspection of the tubing performed.

The inservice inspection requirements contained in the TS and the ASME Code are prescriptive, and strict adherence to these requirements do not alone ensure adequate tube integrity. This problem is aggravated by the fact these prescriptive requirements are out of date, reflecting neither the current dominant forms of degradation or the current inspection technology. However, these requirements can result, in some cases, in unnecessary plugging or repair of degraded tubing since the standard TS tube repair criterion is conservative for many of the kinds of flaws being currently observed.

Despite the shortcomings of current TS and ASME Code requirements, licensees are required by 10 CFR 50, Appendix B, to take action as necessary to ensure that adequate tube integrity is being maintained in accordance with 10 CFR 50, Appendix A. 10 CFR 50, Appendix B, Criterion XI, requires that all testing required to demonstrate that

structures, systems, and components will perform satisfactorily in service is identified and performed and Criterion XVI requires that measures be established to assure that conditions adverse to quality are promptly identified and corrected. Nevertheless, licensees often tend not to focus on the bottom line; ensuring adequate tube integrity. This is because licensees are often not fully aware of the limitations of the current regulatory framework. Implementing a prescriptive set of requirements, whose stated purpose is to ensure adequate tube integrity, tends to impart to the licensee a false sense of security that this goal is in fact being met under all circumstances.

NRC staff has responded to the shortcomings in the current regulatory framework on an ad-hoc basis as necessary to ensure that adequate tube integrity continues to be maintained by licensees. The staff response has included issuance of NRC bulletins and generic letters to address specific problem areas that have developed in the field. In addition, the staff interacts closely with licensees for plants undergoing significant degradation to ensure that licensee programs provide reasonable assurance of adequate tube integrity. Additionally, the staff has reviewed numerous licensee proposals to amend the TS to permit the use of alternative tube repair criteria for application to specific types of flaws, to minimize unnecessary plugging or repairs to degraded tubing. These reviews have been complicated by the fact that they involve issues not addressed in current regulatory guidance. This "ad-hoc" approach to addressing the shortcomings of the current regulatory framework has been very resource intensive.

The staff has concluded that a new regulatory approach which is performance based, rather than prescriptive, is the most efficient approach for resolving the shortcomings of the current regulatory approach and for ensuring adequate tube integrity as is required by 10 CFR 50, Appendix A. A performance based regulatory approach can enable the licensees and NRC staff to readily adapt to new degradation mechanisms and new inspection technology advances. It provides licensees with the flexibility needed to efficiently manage tube degradation while, at the same time, continuing to provide reasonable assurance of SG tube integrity.

The proposed rule requires that the SG tubes are to be monitored and maintained consistent with NRC approved performance criteria such that there is reasonable assurance that the tubing will remain capable of performing their intended safety functions. To this end, the proposed rule requires that the performance criteria are to be established such as to be commensurate with adequate tube integrity. "Adequate tube integrity" is a requirement of 10 CFR 50, Appendix A, and thus is not a new regulatory standard. A formalized process whereby adequate tube integrity is assured is consistent with 10 CFR 50, Appendix B, and thus also is not a new regulatory standard.

In order to assure a balanced approach and maintenance of defense-in-depth, the proposed rule identifies key programmatic elements (i.e., preventive measures, inservice inspection, tube repairs, leakage monitoring, and tube integrity monitoring) to be addressed by utilities in monitoring and maintaining the SG tubes with respect to the performance criteria. Specifics on how these programmatic elements are to be implemented are to be developed

by the licensees. Accordingly, licensees will have the flexibility to determine the appropriate preventive measures, frequency of inspection (i.e., inspection intervals), inspection sample sizes, tube repair criteria, and tube inspection and tube integrity monitoring methods subject to the constraint that the performance criteria are demonstrated to be met.

The proposed rule provides for a formalized process for demonstrating that the performance criteria are met, in lieu of the current ad-hoc approach. This formalized process assures that all licensees are taking action as necessary to ensure adequate tube integrity in accordance with 10 CFR 50, Appendices A and B. Under the proposed rule, licensees demonstrate reasonable assurance that the performance criteria are met by means of monitoring the condition of the tubing with respect to the performance criteria. The rule specifies that tube integrity monitoring shall be performed in such a manner as to provide high confidence in the assessment of the tubing condition relative to the performance criteria.

1.2.5 Performance Criteria

The rule requires that the SG tubes are to be monitored and maintained against performance criteria such that there is reasonable assurance the tubing will remain capable of performing their intended safety functions.

Under the proposed rule, the performance criteria are to be established such as to be commensurate with adequate tube integrity under the conditions of normal operation, including anticipated operational occurrences, design basis accidents, external events, and natural phenomena for which the tubing must perform its intended safety functions.

The rule requirements concerning the specifics of the performance criteria have been developed based on a number of considerations. First the criteria must be consistent with the applicable GDC of 10 CFR 50, Appendix A. Second, the performance criteria must be expressed in terms of parameters that can be directly measured or can be calculated on the basis of direct measurements. Third, the criteria must be designed such that failure to meet the criteria does not pose undue risk to public health and safety.

The rule specifies that the performance criteria shall consist of three parts; namely, criteria pertaining to tube structural integrity, accident-induced leakage integrity, and operational leakage integrity.

The rule specifies that the structural performance criteria shall be such as to require that all tubes in the SGs (remaining in service) retain margins of safety against gross failure and/or rupture that are consistent with the margins implicit in the stress limits of the ASME Boiler and Pressure Vessel Code, Section III, 1989 edition for all service level loadings. This criterion is consistent with the applicable GDC (i.e., GDC 14 and 31). Factors of Safety can be determined from the flaw geometries measured during inservice inspection or directly through such means as in-situ pressure testing. Failure to meet this criterion would increase the likelihood of abnormal leakage or gross rupture of the tubing, but would not be expected

to lead to significant risk since this situation would be revealed in a timely manner during the next inservice inspection. This criterion is consistent with the manner in which flaw evaluation methodologies have been developed for ferritic and austenitic steel piping in the ASME Code, Section XI. (Section XI of the code does not address flaw evaluation methodologies for Inconel SG tubing other than to identify the traditional 40% tube repair limit.) This criterion is also consistent with the basis for the development of RG 1.121, "Bases for Plugging Degraded Steam Generator Tubes," and with the methodologies that have traditionally been applied for flaw evaluations for SG tubing and for developing alternatives to the traditional 40% depth-based tube repair limit.

There is room for interpretation as to exactly what margins of safety are consistent with the margins implicit in the stress limits of Section III of the Code. However, the regulatory guide accompanying the rule provides guidance on this issue consistent with the traditional staff position as given in RG 1.121. Namely, a margin of safety of three against burst should be maintained under normal operating conditions and a margin, under postulated accidents, should be maintained as determined by the stress limits in NB-3225 of Section III of the code.

The rule also permits the structural performance criteria to be expressed in probabilistic terms rather than in deterministic terms as above. Under this alternative approach, the probability of tube ruptures as initiating or consequential events shall be limited such as to ensure compliance with 10 CFR 50, Appendix A, General Design Criteria 14 and 31, and low risk. The probability of tube ruptures may or may not be a measurable quantity depending on whether there is sufficient information available to quantify all significant uncertainties and variabilities in the input parameters and structural models, and thus this criteria may only be utilized where such information is available.

The regulatory guide accompanying the rule provides the specifics of an acceptable probabilistic structural performance criteria consistent with the rule. SG tube ruptures may occur as initiating events under normal operating conditions or as conditional events as a consequence of transient or accident loadings on the tubing. The probabilistic structural performance criteria in the regulatory guide consists of two components. The first component consists of a criterion that applies to the probability of rupture of a single tube occurring as an initiating event; namely, the probability of such events should not exceed 5x10-3 per reactor year. (Simultaneous rupture of more than one tube is not considered to be credible under normal steady state conditions.) This criterion corresponds to the historical frequency of tube rupture events in the U.S. through mid-1996. NRC risk studies (NUREG-0844) indicate the risk associated with this criterion to be small. In addition, the staff considers this criterion to be consistent with GDC-14 (i.e., the reactor coolant pressure boundary shall have an extremely low probability of abnormal leakage and gross rupture). The bounding leak rate associated with a single tube rupture is evaluated as part of the plant licensing basis and demonstrated to involve radiological consequences less than 10 CFR Part 100 guidelines. Thus leakage accompanying a single tube rupture does not constitute abnormal leakage. Furthermore, the risk associated with a given rupture of a single tube, assuming it occurs as an initiating or spontaneous event, is very small compared to the risks

associated with a given rupture of a large diameter reactor coolant pipe or pressure vessel. Thus it is reasonable that the standard for what constitutes an extremely low probability of gross rupture is much smaller for an individual SG tube than it is for a large diameter reactor coolant pipe.

The second component of the probabilistic structural performance criteria in the regulatory guide applies to the conditional probability of rupture of one or more tubes under the most limiting postulated accident, typically main steam line break (MSLB) occurring in conjunction with a safe shutdown earthquake (SSE). Specifically, the conditional probability of rupture under these conditions should not exceed the following:

1) $5x10^{-2}$ for one or more tube ruptures
2) $2.5x10^{-2}$ for two or more tube ruptures
3) 10^{-3} for more than ten tube ruptures

These conditional probability criteria are consistent with criteria previously accepted by the staff in NRC GL 95-05 for developing voltage-based tube repair criteria. The specific criteria in GL 95-05 are actually one-fifth the above values since they apply to conditional probabilities associated with a single degradation mechanism (i.e., outer diameter stress corrosion cracking), whereas the above criteria apply to the total conditional probability of rupture from all degradation mechanisms at a plant. NRC studies (NUREG-0844) indicate these criteria to be sufficient to ensure low risk. In addition, the staff believes these criteria to be an adequate surrogate for anticipated occurrences, transients, and accidents that may occur more frequently than the limiting postulated accident since these more frequent occurrences tend to involve less severe loadings of the tubes. Use of higher values would in the staff's judgement be inconsistent with the intent of the plant licensing basis that the plant be designed to sustain postulated accidents without tube rupture and/or abnormal leakage and, in addition, is inconsistent with GDC-31 that there be sufficient margin during postulated accidents against rapidly propagating fracture.

The proposed rule specifies that the performance criteria applicable to operational primary-to-secondary leakage shall be such as to provide reasonable assurance against abnormal leakage and/or gross rupture of the leaking tube(s) during postulated accidents. This is consistent with the basis of the 500 gallon-per-day (gpd) operational leakage limit contained in the standard TS. Accordingly, the draft regulatory guide accompanying the proposed rule states that an acceptable performance criteria for operational leakage is that operational leakage should not exceed the TS leak rate limit. It should be noted that the existing operational limit in the TS does not eliminate the need for a separate performance criteria pertaining to operational leakage. The purpose of the TS limit is to ensure timely plant shutdown before a rupture occurs should leakage exceed the TS limit. Leakage in excess of the TS limit does not constitute a violation of the TS provided the plant is shutdown within the time interval specified in the TS. However, exceeding the TS limit is reportable in accordance with 10 CFR 50.72 and 50.73, and in addition, licensees must perform an unscheduled SG inspection. For these reasons, licensees typically shutdown the unit before the TS limit is actually exceeded. However, leakage in excess of the TS limit is an

indicator of a potential problem(s) with the licensee's program for ensuring adequate tube integrity. Contributing causes may involve inadequate inspections, inadequate leakage monitoring, higher than expected flaw growth rates, and/or inadequate predictive models for projecting the future condition of the tubing during the most recent operational assessment. By including the operational leakage limit in the TS as a performance criterion, it is assured under the proposed rule that the causal factors leading to the leak will be assessed and appropriate corrective actions taken.

Finally, the proposed rule specifies that the performance criteria for accident-induced leakage shall be such that the calculated, potential leakage associated with the most limiting postulated accident shall not exceed the total charging pump capacity of the primary system and shall be such that the associated offsite radiological consequences are in accordance with 10 CFR Part 100 guidelines and the associated radiological consequences to control room personnel are in accordance with 10 CFR 50, Appendix A, GDC-19. With respect to the radiological consequences, the proposed rule is not imposing a new or more restrictive standard since off-site and on-site doses associated with postulated design basis accidents are currently required to be in accordance with the applicable limits and guidance set forth in 10 CFR Part 100 and 10 CFR 50, Appendix A, GDC-19. Traditionally, radiological assessments relative to these requirements have been performed in accordance with conservative guidance given in the SRP (NUREG-0800). Revised guidelines for performing these radiological assessments are proposed in Section C.9 of the regulatory guide accompanying the proposed rule. The revised dose assessment guidance ensures that doses will continue to be calculated conservatively (although additional flexibility is afforded to the licensee) thereby assuring that Part 100 and GDC 19 remain "tolerable" performance criteria.

1.2.6 Requirements for Managing Tube Degradation

To ensure the performance criteria are met, the proposed rule requires that licensees manage the types, extent, and severity of degradation that may affect the SG tubing. This requirement is consistent with what is already required under 10 CFR 50, Appendices A and B. Of particular note is Criterion XVI of Appendix B; namely, measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Under the proposed rule, management of the degradation is to be accomplished through a combination of programmatic elements identified in the rule. These are specified to assure a balanced approach, i.e. no undue reliance on one particular aspect of maintaining tube integrity thereby maintaining a defense-in-depth approach.

Preventive Measures

The first of these programmatic elements are preventive measures, which are implemented as practical, to minimize the potential for tube degradation and to mitigate active degradation mechanisms. Preventive measures are an implicit requirement of 10 CFR 50, Appendix B, since they relate directly to the identification and correction of conditions adverse to quality (i.e., conditions leading to tube degradation). The administrative controls section of the

sample TS accompanying the proposed rule require that preventive measures include a secondary water chemistry control program and a program to control loose parts and foreign objects in the SGs. The sample TS requirements pertaining to secondary water chemistry control are unchanged from the current standard TS requirements. The sample TS requirement pertaining to the control of loose parts is a new requirement. It states simply that licensees shall have a program for monitoring and control of loose parts and foreign objects to inhibit fretting and wear degradation of the tubing. The need for this requirement is evidenced by the fact that three of the nine tube ruptures that have occurred to date, worldwide, have been as a consequence of tube damage caused by loose parts and foreign objects, and thus measures to monitor and control loose parts are a key element for ensuring compliance with 10 CFR 50, Appendices A and B. Additional guidelines for implementing preventive measures are provided in the regulatory guide accompanying the proposed rule.

Inservice Inspection

The second of these programmatic elements identified in the proposed rule involves inservice inspection of the tubing with respect to the applicable acceptance criteria (i.e., tube repair criteria) for degraded tubing. Inservice inspections to this effect are already a requirement of the TS. However, the sample TS accompanying the proposed rule have been revised relative to the current TS to make it performance-based rather than prescriptive, where practical. The sample TS require that the SGs shall be inspected at a frequency as necessary such that it can be demonstrated by operational assessment (discussed below) that the performance criteria will continue to be met prior to the next scheduled inspection. (Note that determination of an appropriate inspection interval consistent with satisfying the performance criteria is a key objective of the operational assessment.) This contrasts with current TS requirements which specify inspection intervals not to exceed 24 to 40 calendar months, depending on the number of indications found during the most recent inspection. The proposed new requirement addresses a major shortcoming in the existing requirement, since it has frequently been necessary for the staff to request that licensees commit to inspection intervals of less than 24 months (to as low as 3 months) for severely degraded units to ensure adequate tube integrity. (Recent examples involve Palo Verde 1, 2, and 3, ANO-1, Maine Yankee, Braidwood 1, and Byron 1.)

The TS currently require a 3% initial sample, with additional inspection samples to be performed depending on the number of indications found during the initial sample. Additional inspection samples must be performed if 1 or more defective tubes are found or if 5% of the inspected tubes are found to be degraded. These additional inspections may be limited such that the total number of tubes inspected need not exceed 9 to 21% of the tube population provided the rate of defective tubes found does not exceed 1% and the rate of degraded tubes does not exceed 10% of the tube population. Where the rate of defective or degraded tubes found exceed these criteria, all tubes in the SG must be inspected. These requirements suffer from significant shortcomings with respect to ensuring adequate tube integrity. The 3% initial sample is much too small to provide an early warning of a newly emerging degradation mechanism such that more intense sampling will be implemented on a timely basis. As an illustration, assume that 0.3% of the tubes contain detectable flaws (i.e.,

10 tubes in a Westinghouse SG or 47 tubes in a B&W SG contain flaws). A 3% inspection sample would have a probability of only 0.27 of including even 1 tube containing a detectable indication. Even with 1% of the tube population containing detectable indication, the probability for inspecting at least one of the affected tubes is only 0.64. Another significant shortcoming is that even in cases where indications are found during the initial sample, the sampling strategy is not designed to ensure that all potentially affected tubes are inspected in cases where the rate of indications found is less than 1% defective or 10% degraded. Thus, even if indications which have serious tube integrity implications are being found randomly throughout the SGs, the total inspection sample need not exceed 21% even though up to 1% of the 79% of the tubes which are uninspected can be reasonably inferred to be defective.

To address these shortcomings, the proposed sample TS requires that an initial 20% random inspection sample be performed for purposes of identifying active degradation mechanisms. Should active degradation mechanisms be identified during this initial sample, an expanded inspection shall be performed in the specific regions of the tube bundle affected by each active mechanism. The inspection sample size within these specific regions shall be 100% or as necessary to demonstrate as part of the operational assessment that the performance criteria will continue to be met. The staff acknowledges that the proposed 20% initial sample size is a prescriptive requirement which does not have a direct relationship with the performance criteria. However, the 20% initial sample is sufficient to alert the licensee to the emergence of a newly active degradation mechanism such as to ensure timely implementation of expanded sampling consistent with meeting the performance criteria. The 20% initial sample is consistent with what is recommended in the EPRI Steam Generator Examination Guidelines which has gained wide acceptance among licensees. It ensures that at least one tube will be included in the sample with a probability of 0.88 given the emergence of a new active degradation mechanism involving detectable indications in 0.3% of the tube population will be detected. If 1% of the tubes are affected, the 20% initial sample will include at least one of the affected tubes with a probability of 0.99.

Paragraph (b)(4)(ii) of the proposed rule requires that inservice inspection systems (i.e., techniques, procedures, and personnel) shall be used which have been demonstrated to be reliable for all flaw mechanisms affecting the tubing such that plugging or repairs may be implemented before the performance criteria are exceeded. This requirement is consistent with what is already required under 10 CFR 50, Appendices A and B. Of particular note is Criterion IX of Appendix B which specifies that measures shall be established to assure that NDE is controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, etc. The NDE method used for inservice inspection of SG tubes is eddy current testing (ECT). Qualification requirements for ECT equipment and procedures are given in ASME Code, Section XI, Appendix IV, and basically involve calibration on reference standards with drilled holes and electric discharge machining (EDM) notches. ECT personnel for data acquisition and analysis must be qualified in accordance with the ASME Code, Section XI, IWA-2300 and Appendix IV. These requirements have proven inadequate to ensure ECT reliability for flaw detection and sizing. These requirements suffer fundamentally from the lack of performance

demonstration requirements on statistically significant data sets for the types of flaws and accompanying circumstances actually being encountered in the field. Thus, it has frequently been necessary for licensees to implement measures beyond code requirements, frequently at the staff's request, to ensure a reliable inspection as necessary to ensure adequate tube integrity. Such measures have been ad-hoc and have frequently included the use of advanced ECT equipment and procedures beyond minimum code requirements and destructive examinations of tubes removed from the field to validate field ECT results.

The industry has long recognized the need to upgrade the qualification requirements for ECT systems. The industry has developed an enhanced protocol for the qualification and performance demonstration of ECT systems and incorporated this protocol into the EPRI Steam Generator Examination Guidelines. Appendix G of these guidelines addresses ECT personnel qualification and Appendix H addresses ECT technique (i.e., equipment and procedures) qualification. At its own initiative, the industry has qualified all personnel to these guidelines. In addition, the industry has developed techniques qualified to these guidelines for detection of all flaw mechanism identified to date. However, the industry continues to work to develop qualified techniques that can size cracks. To date, the industry has not successfully demonstrated to the NRC a qualified technique for sizing cracks.

Although these guidelines have served to significantly improve the quality of inspection, the EPRI qualification guidelines exhibit two significant shortcomings. The flaws in the qualification data sets are frequently not representative of actual flaws in the field in terms of their signal response and signal-to-noise characteristics. In addition, personnel performance for flaw detection and sizing is evaluated subjectively (i.e., against the opinion of expert analysts) rather than objectively (i.e., against the actual presence and geometry of the flaw).

The staff has concluded that implementation of the EPRI qualification protocol for a given application (i.e., degradation mechanism and accompanying circumstances) ensures a minimum level of proficiency of the ECT system for flaw detection such that paragraph (b)(4)(ii) of the proposed rule is satisfied. Thus, the sample TS specify that, as a minimum, techniques used to address each active degradation mechanism shall be qualified for detection in accordance with the EPRI guidelines. However, the staff also concludes that the detection and sizing performance achieved during the EPRI qualification performance may or may not be fully representative of the performance that can be expected in the field. For this reason, the sample TS require that NDE techniques and personnel be "validated" for purposes of evaluating the NDE signals viz-a-viz the tube repair criteria and for purposes of supporting condition monitoring and operational assessments. This is necessary to ensure compliance with paragraphs (b)(4)(ii), (iii), and (iv) of the proposed rule. Validated techniques and personnel are those that have been qualified in accordance with the EPRI guidelines and which have undergone supplemental performance demonstration for purposes of quantifying the expected detection and sizing performance which can be achieved in the field. Where no validated techniques are available for a particular degradation mechanism, the sample TS require that indications associated with the subject degradation mechanism shall be plugged upon detection and that condition monitoring and operational assessment

shall not be based on the NDE sizing measurements. Again, this requirement is necessary to ensure compliance with paragraphs (b)(4)(ii), (iii), and (iv) of the proposed rule.

Plugging and/or Repair

The third programmatic element identified in the proposed rule involves the plugging and/or repair of tubes which fail to meet the acceptance criteria (i.e., tube repair criteria). This is not a new requirement. It is already required in the standard TS as a prerequisite for determining the SGs to be OPERABLE. This requirement is also included in the sample TS accompanying the proposed rule.

The sample TS specify that the tube repair criterion shall be 40% of the nominal tube wall thickness, subject to demonstrating by operational assessment that the performance criteria will continue to be met prior to the next scheduled inspection. The 40% criterion is consistent with the current standard TS requirement. However, that its use is conditional is a new TS requirement that is necessary to ensure compliance with 10 CFR 50 Appendices A and B. The original basis for the 40% criterion was based in part on the assumption that incremental flaw growth between inspections and flaw measurement error together would not exceed about 20% of the wall thickness, such that tubes satisfying the criteria would be expected to have adequate integrity at the time of the next scheduled inspection. However, operating experience has demonstrated that incremental flaw growth and flaw measurement error may frequently exceed the assumed values of these parameters. In these kinds of situations, the staff has requested that licensees to plug all indications upon detection and/or to shorten the time interval between inspections as necessary to ensure adequate tube integrity.

The sample TS include a clarification that the 40% criterion is applicable to the maximum measured depth of the indication. This clarification is consistent with the way the current requirement has been interpreted by licensees and the staff to date. The clarification is needed however, since licensees are expected to propose that the 40% criterion apply to the average measured depth of the indication. This interpretation has implications with regard to potential leakage under postulated accident conditions. The subject clarification ensures that licensees develop the appropriate technical justification for staff review and approval (as part of a TS amendment request) prior to implementing a revised interpretation.

The sample TS state that alternative repair criteria (ARC) may be developed and implemented in lieu of the 40% criterion as part of a SG degradation specific management (SGDSM) strategy (without a change to the TS and without NRC review and approval). SGDSM provides for the use of the most appropriate inspection, assessment, and repair procedure for different types of degradation. Per the sample TS, SGDSM constitutes an integrated approach consisting of an operational assessment methodology, specific inservice inspection programs (with specified frequency and level of sampling, specified qualified/validated NDE techniques), and repair limit computational methods aimed at ensuring that the performance criteria for tube integrity are met prior to the next scheduled inspection. The ARC associated with an SGDSM strategy may not be a fixed value, but

may involve a computational method to be implemented as part of the operational assessment for determining an acceptable ARC value which is consistent with ensuring that the performance criteria for tube integrity are met prior to the next scheduled inspection. The sample TS further states that SGDSM strategies and their technical bases shall be documented in a technical report that is referenced in the plant procedures as the methodology for implementing the associated ARC.

1.2.7 Operational Leakage Monitoring

Primary-to-secondary leakage monitoring is an important defense-in-depth measure which can assist plant operators in monitoring overall tube integrity during operation. Monitoring also gives operators information needed to safely respond to situations in which tube integrity becomes impaired and significant leakage or tube failure occurs. Leakage monitoring and appropriate leakage limits are important constituents of an effective leakage monitoring program which licensees should implement to ensure that operational leakage performance criteria are met, as required by the draft rule.

Current primary-to-secondary leak rate limits contained in plant TS have two objectives. First, to ensure that the dose contribution from tube leakage will be limited in the event of a design basis SG tube rupture or main steam line break (MSLB) accident. Second, to prevent the propagation of cracks to tube rupture under MSLB or loss of coolant accident conditions (LOCA). The operational leak rate limit, in common use, is 500 gpd through any one steam generator and 1 gpm through all steam generators.

The proposed revisions to the TS for primary-to-secondary leakage are part of a comprehensive leakage monitoring program which should be followed by licensees implementing the proposed rule. Although leak-before-break has not been conclusively demonstrated for SG tubes, setting forth leakage limits in the TS is necessary to ensure a level of defense in depth against unacceptable primary-to-secondary leakage. The need for the revised limits to be included in TS also has a practical motivation. Operators must promptly respond to developing leakage situations so that the benefits of the leakage limits can be realized. Confusion introduced by differences between TS and administrative leakage limits could cause delays in taking appropriate action upon detection of elevated operational leakage.

10 CFR 50.36, "Technical Specifications," gives criteria for the establishment of TS limiting conditions for operation (LCO). Primary-to-secondary leakage limits are process variables applied as operating restrictions to ensure that initial conditions assumed for design basis accidents are not exceeded. Further, the accidents under consideration involve the failure or integrity challenge of a fission product barrier. Thus, Criterion 2 in 10 CFR 50.36 applies for primary-to-secondary leakage limits.

The proposed leakage limits of 150 gpd from a SG and 60 gpd per hour change in leak rate were recommended in guidance provided by EPRI Report TR-104788, "PWR Primary-to-Secondary Leak Guidelines," May 1995. Also, a number of facilities have adopted similar

limits when implementing the alternate repair criterion under Generic Letter 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking." Licensee use of limits similar to those proposed has not indicated an undue operating burden. In fact, plants have historically shut down facilities well in advance of reaching the current TS limits. Thus, the proposed limits do not appear to overly restrict plant operations especially in light of the expected relaxation of tube repair criteria under the proposed rule.

The revised leakage limits help reduce the potential of a SGTR. However, the accident leakages anticipated under the provisions of the rule allowing alternate tube repair criteria are calculated values of the assumed effect of elevated tube differential pressure. The predicted accident leakage values are greater than the leakage currently assumed for MSLB or other events challenging tube pressure integrity. The maximum operational leak rate limit provides assurance that the dose contribution from tube leakage, in conjunction with the allowable coolant activity limit, will be limited to less than 10 CFR 100 limits.

The leak rate increase limit is a defense-in-depth measure to help prevent tube rupture. Industry experience has shown that the rate of increase in leak rate rather than the absolute value of leak rate is a strong indicator of a structurally impaired tube. Review of operational data indicated that a limit on the rate of change in measured leak rate could be consistent with the objectives of safe operation by commencing timely shutdown and maintaining plant reliability by avoiding unnecessary shutdowns. The staff has issued Information Notices 88-99, 91-43, and 94-43 to alert licensees to the potential for and the implications of rapidly increasing primary-to-secondary leakage. Use of this limit is necessary since the rule will permit more extensive tube degradation than has been allowed previously. The limit helps assure that the potential for tube rupture is not significantly increased under circumstances that might exist under the proposed rule.

The revised primary-to-secondary leakage limitations are more restrictive than current TS requirements. This change is justified in light of other changes in tube conditions allowed under the proposed rule.

The provisions of 10 CFR Part 50.109, "Backfitting" allow for the application of such requirements when the action is necessary to maintain facility compliance with other Commission rules. 10 CFR Part 50, Appendix A, GDC 30, "Quality of Reactor Coolant Pressure Boundary" requires means for detecting and, to the extent practical, identifying the source of reactor coolant leakage. Further, GDC 14, "Reactor Coolant Pressure Boundary," requires that the reactor coolant pressure boundary have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture. Under the proposed SG integrity rule, tube repair criteria may be used that permit higher levels of tube degradation than is now accepted. Thus, it is appropriate to apply these revised leakage limits to ensure compliance with established rules for reactor coolant leakage detection and reactor coolant pressure boundary integrity, by maintaining a sufficient balance between prevention of tube damage and mitigation of tube leakage that may be more likely to occur.

The proposed limits do not preclude the possibility that a SG could have degraded tubes that might not withstand the conditions resulting from a MSLB. However, the limits provide additional margin during normal and postulated accident conditions compared to current TS limits. Since the effect on the margin of tube integrity can not be forecast under alternate repair criteria allowed by the proposed rule, additional margin to tube failure is a necessary measure to maintain a balance between prevention and mitigation of tube failure.

Reduction in the operational leakage limit below 150 gpd value would provide for added margin against burst. However, there is a limit to the rupture prevention benefit that can be achieved by applying lower leakage limits. Further reduction in the limit could cause undue restrictions on plant operation and result in unnecessary plant outages, radiation exposure, and repair costs.

TS leakage limits are necessary under the proposed rule based on the requirements in 10 CFR 50.36. Revision of the TS limits will help avoid confusion with proposed administrative leakage limits proposed by industry, which are already in effect at several facilities. The compliance exception in 10 CFR 50.109 applies to the revised limits since they are intended to maintain defense-in-depth by compensating for reduced tube integrity margins which would result under the proposed rule.

1.2.8 Condition Monitoring

The fifth programmatic element of the proposed rule is to monitor the "as-found" condition tubing during each inservice inspection with respect to the performance criteria. This programmatic element is termed "condition monitoring" and is "backward looking" in that its purpose is to confirm that adequate tube integrity has been successfully maintained since the previous inservice inspection. This proposed requirement is necessary to ensure compliance with 10 CFR 50, Appendices A and B.

Condition monitoring consists of two components. The first component consists of characterization of the tubing condition from the inservice inspection results and/or by employing alternative test methods (such as in-situ pressure testing). The second component consists of evaluating the inspection and/or test results with respect to the performance criteria. Condition monitoring must be performed with a high degree of confidence to assure that the performance criteria are being satisfied. Paragraph (b)(4)(iv) of the proposed rule specifies that condition monitoring utilize inspection and/or test methods and evaluation methods such as to provide high confidence in the assessment of the condition of the tubing relative to the performance criteria. In effect, the proposed rule is stating that licensees must ensure compliance with 10 CFR 50, Appendices A and B, with high confidence.

The sample TS accompanying the proposed rule state that the condition of the tubing may be characterized from the inservice inspection results provided the sizing performance of the techniques and personnel have been "validated" (as defined earlier) for the subject application of the techniques. "Validation" of sizing performance is necessary to ensure that flaw size measurement uncertainty is explicitly accounted for in determining the condition of

the tubing. Alternative test methods (such as in-situ pressure testing) may be used in lieu of or to supplement the inservice inspection results as a basis for establishing the condition of the tubing. In addition, the sample TS require that evaluation methods shall be developed, as necessary, to allow the condition of the tubes to be evaluated with respect to the applicable performance criteria. The sample TS require that these methods shall account for all significant uncertainties which may affect the outcome of the evaluation in order to ensure that the assessment of tubing viz-a-viz the performance criteria is performed with high confidence in accordance with the proposed rule. The sample TS quantifies the level of confidence to be assured.

Paragraph (b)(2) of the proposed rule and the accompanying sample TS requires that the licensee shall notify the NRC within 24 hours and shall take appropriate corrective action if the condition of the SG tubes does not meet the performance criteria. This special reporting requirement replaces the prompt reporting requirement in the current TS which applies when the rate of defective tubes found during inservice inspection exceeds 1% of the tubes inspected or the rate of degraded tubes found exceeds 10% of the tubes inspected. Under the proposed rule, the reporting threshold is related directly to performance criteria commensurate with adequate tube integrity compared to the current reporting threshold which is arbitrary and not directly related to the condition of the tubes viz-a-viz the performance criteria. The proposed 24 hour reporting requirement is sufficient to ensure that the staff can take timely follow-up action when warranted. The proposed requirement to take appropriate corrective action is consistent with what is required under 10 CFR 50, Appendix B.

1.2.9 Operational Assessment

The sixth programmatic element of the proposed rule is to monitor the projected condition of the tubing calculated to exist during future operation with respect to the applicable repair criteria. Corrective actions must be implemented, as necessary, to ensure that the performance criteria are met. This programmatic element is termed "operational assessment" and differs from condition monitoring in that it is "forward looking" rather than "backward looking." Its purpose is to demonstrate reasonable assurance that the performance criteria will continue to be met during future operation. This proposed requirement is to demonstrate reasonable assurance that the licensees program will continue to meet 10 CFR 50, Appendices A and B.

Operational assessment involves characterizing the tubing condition which is projected (calculated) to exist immediately prior to the next scheduled inspection viz-a-viz the performance criteria. Paragraph (b)(4)(v) of the proposed rule specifies that operational assessment utilize evaluation methods that provide high confidence in the evaluation of the projected condition of the tubing relative to the performance criteria. Accordingly, the sample TS requires that evaluation methods shall be developed to calculate the projected condition of the tubing and to assess this condition relative to the applicable performance criteria. These methods shall account for all significant uncertainties which may affect the outcome of the evaluation in order to ensure that the assessment of tubing viz-a-viz the

performance criteria is performed with high confidence in accordance with the proposed rule. The sample TS quantifies the level of confidence to be assured.

1.2.10 Routine Reporting Requirements

The sample TS require that the licensee submit a report within 90 days following restart from each inspection outage describing the inservice inspection, condition monitoring, and operational assessments performed and the results. This requirement replaces the existing requirements for reporting the number of tubes plugged within 15 days of plant restart and for reporting the complete results of the inservice inspections within 12 months. Because licensees will have increased flexibility under the proposed rule for managing tube degradation, the enhanced reporting requirement is needed to ensure that the staff can effectively monitor the effectiveness of licensee programs for ensuring adequate tube integrity.

1.2.11 Mitigation of Abnormal Leaks or Gross Rupture

The SG rule includes the requirement for licensees to maintain measures for mitigating abnormal leaks or gross rupture of the tubes. This is not a new requirement and the rule is not intending to revise or add to previous requirements in this area. Instead, the requirement is included in the rule since the staff recognizes that tube rupture and leak mitigation is an important part of a balanced, defense-in-depth approach to ensuring adequate protection to public health and safety.

1.2.12 Radiological Dose Assessment

One of the performance requirements of the SG rule is that licensees meet the accident-induced leakage criterion. The accident-induced leakage criterion requires that the consequences of a postulated accident must not result in leakage which exceeds charging pump capacity or in doses which would exceed the guidelines of 10 CFR Part 100 or a small fraction of Part 100 guidelines, as appropriate to the accident and that the associated radiological consequences to control room personnel are in accordance with GDC 19 of Appendix A to 10 CFR Part 50. The manner in which licensees may demonstrate that the accident-induced leakage criterion can be met is described in RG X.XX.

For licensees which have not experienced degradation of their SG tubes, normal operating leakage and accident (event)-induced leakage will not be greater than the TS value for normal operating primary to secondary leakage contained in the plant's TS. Therefore, it is likely that the existing dose assessments of postulated accidents have already demonstrated that the guidelines of Part 100 or a small fraction of Part 100 are met and that the guideline dose of GDC 19 is also met. Since these assessments usually incorporated the TS values for primary to secondary leakage and the maximum instantaneous reactor coolant system (RCS) activity level of dose equivalent ^{131}I and 48 hour value of dose equivalent ^{131}I into the assessment and since the assessments demonstrated that Part 100 and GDC 19 were met, the performance standard for demonstrating that the accident-induced leakage criterion is met is

by maintaining the RCS activity levels of dose equivalent ^{131}I and primary to secondary leakage below TS limits. The staff does not anticipate that any licensee would be required to perform additional assessments to demonstrate that the accident-induced leakage criterion has been met nor would any new TS nor revisions to existing TS be anticipated to bring operating conditions in accordance with the assumptions from the accident analyses.

However, for those licensees which have experienced degradation of their SG tubes to a level that the combination of normal operating leakage and event-induced leakage from a postulated accident is expected to be greater than the TS value for normal operating leakage, then they may opt to utilize the flex program which is described in RG X.XX. Selection of the flex program necessitates the acceptance of different dose criteria for MSLB and SGTR accidents and fuel damage related accidents from that currently contained in SRP sections 15.1.5 and 15.6.3. In addition, selection of the flex program also necessitates changes in the TS for the maximum instantaneous and the 48 hour value of dose equivalent ^{131}I.

Utilization of the flex program is purely voluntary. The flex program provides both the licensee and the staff the opportunity to conserve resources. As an example, currently, when licensees wish to implement the interim plugging criteria discussed in GL 95-05, they frequently are required to reanalyze the consequences of a MSLB. As the conditions of the tubes continue to degrade, continued reanalyses are required of a MSLB with continuing increases in the assumption of the quantity of event-induced leakage resulting from the MSLB. With the increased primary to secondary leakage, typically, reductions in the TS values for dose equivalent ^{131}I are required. These changes to the TS values require staff review prior to restart of the plant. In addition, the necessity for the reduction in the TS values is frequently not known until the inspection of the SGs is completed during the outage. The submittal and processing of such an amendment request is not in the best interests of public health and safety. Utilization of the flex program eliminates the need for evaluations by either the licensee or the staff to be done in a crisis mode. It establishes an orderly process for the review and focuses on the evaluation of projected leakage from the tubes. It allows licensees to perform, when tube degradation is initially determined, an analysis of the consequences of the limiting accident for the facility and to establish a plot for TS purposes of the sum of the normal operating and event-induced primary to secondary leakage as a function of the maximum instantaneous RCS activity level of dose equivalent ^{131}I and the 48 hour RCS activity level of dose equivalent ^{131}I.

Utilization of the flex program does necessitate some changes in the acceptance criteria associated with accidents typically analyzed by licensees. For those licensees which are not utilizing the flex program, the dose criteria for the exclusion area boundary (EAB) and low population zone (LPZ) doses remain the same, a function of the case, full Part 100 values for a pre-existing spike and 10% for an accident initiated spike. However, for the flex program, the dose criteria is not a function of case but of the postulated accident. For a MSLB, the criteria are full Part 100 dose guidelines. This is a relaxation from the existing criterion which is 10% of Part 100. For a SGTR, the dose criterion is 10% of the full Part 100 guidelines. This is more limiting for the pre-existing spike case which was previously the full Part 100 guidelines. The basis for selecting dose criteria as a function of accident

rather than the case was that the SGTR is considered to be more of a probable event than a MSLB. To date there have been no MSLBs while there have been seven SGTRs. Consequently, the staff considers the SGTR to be a much more probable event especially if one allows tubes to remain in service which previously were removed from service.

1.2.13 Implementation of the Proposed Rule

To implement the rule, the current TS must be amended to incorporate the new regulatory framework (i.e. the current TS precludes implementation of the rule). As discussed above, the current TS requirements are a rigid, prescriptive regulatory approach. The amended TS would revise this framework and enable appropriate elements (i.e. those important to determining the operability of SGs when going from mode 5 to mode 4) from the SG rule's performance-based approach to be incorporated into the TS.

In all cases, these requirements are translations of the SG rule requirements into the TS and are justified based on the previous arguments that supported the rule requirements.

1.2.14 Severe Accident Risk Requirements

The risk related requirements incorporated into the draft SG rule could not be justified for generic imposition on PWR licensees per the exception criteria of 10 CFR 50.109(a)(4). Current regulations do not require PWR licensees to take actions to reduce risk below a level associated with their current licensing basis, and as such, additional risk requirements could not be shown to satisfy the compliance exception provisions of 50.109(a)(4)(i). The staff risk assessment performed in support of the draft proposed SG rule did not reveal a level of risk associated with severe accident induced SGTRs that caused the staff to conclude that additional risk requirements are needed to ensure adequate protection to public health and safety. As such, additional risk requirements failed to satisfy the adequate protection exception provisions of 10 CFR 50.109(a)(4)(ii).

Since additional risk requirements could not be imposed on PWR licensees per 50.109(a)(4), the staff pursued imposing such requirements per 50.109(a)(3) on a value-impact assessment basis. Sections 3 and 4 of this regulatory analysis discuss the details of the value-impact assessment for the draft SG rule.

2. Identification and Preliminary Analysis of Alternative Approaches

2.1 General

This section of the Regulatory Analysis deals with the identification and evaluation of approaches to the problem based upon Section 4.2 of NUREG/BR-0058 as follows:

> "Once the need for action has been identified, the regulatory analysis should focus on identifying reasonable alternatives that

have a high likelihood of resolving the problems and concerns and meeting the objectives identified in Section 4.1.1."
[Note: Section 4.1.1 deals with the background of the problem and is discussed in Section 1.1 of this Regulatory Analysis.]

In determining the most optimum and effective approach for addressing the problems enumerated in the previous section of this report, a number of alternatives should be considered. These alternatives range from "taking no action" to developing new approaches that would embrace performance-based criteria. In assessing these alternatives, the staff has selected the following set of broad evaluation criteria and basic considerations to apply to each option.

- *Performance-based* Establish regulatory/safety objectives without being prescriptive about how they are to be accomplished. The objectives should be clearly defined, measurable, and verifiable, with acceptance criteria that allow a common understanding between the NRC staff and licensees about how performance would be judged.

- *Cost-effective* Cost-effective to both the staff and the industry through the utilization of generic requirements thereby reducing or eliminating the need to process TS changes on a plant specific basis.

- *Flexible* Establish a regulatory framework that will accommodate changes in operating experience and technology and allow licensees flexibility to select cost-effective methods for implementing the objective.

- *Incentive* Establish a regulatory framework that will encourage and reward improvements in technology and operations. When considered in conjunction with repair criteria that are degradation specific (i.e., derived for a given degradation mechanism considering what should be appropriate performance parameters to ensure tube integrity), the action would offer incentives to licensees to make use of more advanced technology.

- *Balanced* Establish a better balance between the elements of defense-in-depth (i.e., the initiating events, maintaining tube integrity, and mitigation).

- *Risk-informed* Risk considerations will be used to develop the regulatory framework and associated regulatory guidance such that the regulatory approach ensures that an acceptable level of risk is maintained. In this regard, risk will be complementary to an approach that ensures current regulations continue to be met and that defense-in-depth is maintained in light of the risk significance of tube integrity.

- *Regulatory consistency* Establish consistent objectives that are derived from safety and risk considerations, and focus on attributes of the design features, programs, and processes needed to protect public health and safety.

- *Enforceable* Through the performance-criteria set forth in a regulatory guide and implemented in standard TS and adopted by licensees, the action would have uniform enforceable provisions.

2.2 Regulatory Alternatives

The following table (Table 2.1) lists the staff requirement criteria for various regulatory actions and a number of regulatory alternatives that could be implemented. However, only a few provide the full spectrum of desired results. Some were eliminated by inspection due to obvious reasons. For other cases where regulatory action would be possible for a limited set of remaining alternatives, a brief explanation is provided. Subsequently, the selected alternative is identified and evaluated in terms of best complying with the staff criteria.

Table 2.1
IDENTIFICATION & PRELIMINARY ANALYSIS OF ALTERNATIVE APPROACHES

				CRITERIA				
POSSIBLE REGULATORY ACTIONS	(1) Performance-Based	(2) Cost-effective	(3) Flexibility	(4) Provides Incentives	(5) Balanced	(6) Risk-informed	(7) Establish Regulatory Consistency	(8) Enforceability
1. Take no action - process plant-specific TS changes	No	No	No	No	No	No	No	Yes
2. NUREG	Yes	Yes	Yes	Yes	Yes	Yes	No	No
3. Regulatory Guide	Yes	Yes	No	Yes	Yes	Yes	Yes	No
4. Generic Letter, or Bulletin	Yes	No	Yes	Yes	Yes	Yes	No	Yes
5. Policy Statement	N/A	N/A	N/A	N/A	N/A	Yes	Yes	No
6. Maintenance Rule	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
7. Develop TS to cover SG tube integrity	No	No	No	No	No	Yes	No	Yes
8. Rulemaking and Regulatory Guide	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

2.2.1 Do Nothing/Continue With Plant-Specific TS

This alternative would maintain the status-quo and necessitate a continuation of plant-specific reviews of licensee submittals in filing for TS changes. This approach does not satisfy the staff criteria shown above. Specifically, it would not (1) be cost-effective since it would require a large expenditure on resources for both the industry and the NRC; (2) serve to establish regulatory consistency and would res[illegible] in inconsistencies (such as on a plant-specific basis in-service inspection program); ([illegible]) be risk-based in being able to address

related accident-based issues (such as consequences of SG tube failure/source term considerations); (4) be performance-based as proposed TS changes would be specific and deterministic for each plant; and, (5) provide for incentives to industry to develop improved inspection techniques and repair methods. Overall, this alternative would not be viable for achieving the desired goal for the proposed regulatory action for a balanced and flexible performance-based program.

2.2.2 Issue NUREG

Generally, special reports on a variety of regulatory, technical, and administrative issues are frequently issued by the NRC. They are prepared by either the staff or by consultants and present the results obtained from analyses and experimental programs that are of interest to the public and the industry. The information is not required action and does not set forth guidance for regulatory consistency. Overall, NUREG reports do not provide an enforceable regulatory base. As such, this alternative is not a viable option.

2.2.3 Issue Regulatory Guide

Regulatory guides describe to the industry and the public, methods acceptable to the NRC staff for implementing specific parts of NRC regulations. They also delineate techniques used by the staff in evaluating specific programs, or postulated accidents, or providing guidance to licensees. The staff plans to include performance-criteria for SG tube integrity in a regulatory guide. The regulatory guide would become an integral part of the entire regulatory program to implement the performance-based program concerning SG tube integrity. However, sole issuance of such a regulatory guide by itself while meeting nearly all of the stated staff criteria, does not ensure uniform implementation for licensees and enforceability by the staff.

2.2.4 Issue Generic Letter (or Bulletin)

Generic Letters are prepared primarily to inform applicants and licensees of regulatory requirements related to licensing matters and issues of compliance. These letters also serve to clarify NRC policy, request information, and transmit information. While aspects of the SG tube integrity program could be presented in generic letters as has been done in the past (such as GL 95-03 and 95-05) licensees can choose to take exceptions to GL guidance. However, when TS are adopted by licensees in response to GLs, they would be enforceable. On the other hand, inconsistent implementation could result in case-by-case exceptions and resultant inconsistencies in TS. Plant-specific reviews would still be required which could be resource intensive. As such, a GL approach is a viable alternative to address the current regulatory framework problem provided that the governing regulations are adequate and the appropriate requirements are incorporated into the TS.

Bulletins are used to transmit information to, and to request action and/or a written response from licensees. Bulletins are also used to obtain specific actions on a one-time basis; i.e., special inspections, surveys, or checks to determine whether certain events and/or conditions

may have generic applicability. The bulletins are not intended to substitute for new or revised license conditions or requirements and would not be suitable for addressing the current SG tube integrity problem.

2.2.5 Policy Statements

Policy statements are generally pronouncements of NRC policy pertaining to some particular matter under consideration (such as NRC rule and regulations). They may provide some regulatory insights and guidance and even clarification of Commission policy to the staff for issues under consideration. However, they are not enforceable as would be a rule, or a TS (via a GL) and therefore policy statements are not viable solutions.

2.2.6 Maintenance Rule

A principal alternative to developing the SG rule is to allow the SG tubes to be addressed as part of the maintenance rule. The maintenance rule is performance-based within which it appears that at least the maintenance and inservice inspection aspects of SG tube integrity could be addressed. The maintenance rule contains a number of shortcomings which cause the staff to conclude that it is not the most effective regulatory approach rule out for use in resolving SG tube concerns. These shortcomings are summarized here for clarity:

1. SG tube ruptures, in terms of risk to the health and safety of the public, are a dominant risk contributor. The SG tubes serve both as part of the reactor coolant pressure system boundary and containment (for scenarios where secondary system integrity is lost). Thus, the SG tubes are a principal barrier against uncontrolled fission product releases to the environs.

   The safety significance of SG tube integrity is relatively high. PWR IPEs typically show SGTR as a dominant risk contributor to total plant risk since SGTR results in a containment-bypass path (even though CDF for tube ruptures are small). Consequently, the staff believes that it is necessary from a regulatory standpoint to more closely monitor SG tube integrity than would occur utilizing the maintenance rule. The staff believes that it is necessary to establish NRC approved performance criteria to ensure SG tubes remain capable of performing their safety function. This is preferred compared to allowing licensees to establish goals per the maintenance rule.

2. If the staff used the maintenance rule, it would be necessary to either maintain TS for repair/inspection of tubes or provide the equivalent lower echelon criteria. This approach would not reliably resolve the current problems associated with the TS governing SG tube surveillance and maintenance, but would perpetuate the current resource problems associated with trying to implement new alternate repair criteria.

3. To establish SG rule performance criteria requires the consideration of a broad range of technical issues that would typically be beyond the scope of the maintenance rule.

This includes radiological protection, primary-to-secondary leakage monitoring, risk management, severe accident, and systems issues. This broad view is needed if the performance criteria are to be balanced and not impose requirements that are unduly (economically) onerous in light of the safety significance involved. The SG rule effort is more expansive than the maintenance rule and allows a better balance to be achieved to ensuring SG tube integrity. This approach ensures a defense-in-depth which is consistent with the fact that the SG tubes function as both the reactor coolant system pressure boundary and containment barrier.

4. The SG rule and RG are being developed in part to enable the application of repair criteria that are applicable to specific forms of degradation. This involves use of appropriate inspection techniques, inspection scope, consideration of NDE uncertainty, consideration of degradation growth rates, and development of structural and leakage empirical correlations. The staff has concluded that development of a SG rule which is in part being structured to allow the flexibility to implement the degradation specific approach is a more effective regulatory approach than attempting to adapt the maintenance rule to this type of application.

In summary, the SG tubes are an essential part of the reactor coolant pressure boundary and as such a high degree of safety significance is placed upon their integrity to perform their intended safety function under a range of conditions including normal operation, operational transients, plant shutdown transients, and accident conditions. It is believed that the relatively narrow scope of the maintenance rule as discussed above within the framework of monitoring the performance and condition of SSC, would not provide the requisite level of assurance for the range of stated conditions. Because of the high degree of safety significance placed upon SG tube integrity, it is therefore prudent to consider a separate and more focused rule (or equivalent regulatory approach) for the SG tube integrity rather than to apply the limited scope and provisions of the maintenance rule. In addition, considerations that pertain to severe accidents do not appear to be appropriate in the framework of the maintenance rule.

2.2.7 Develop TS

While enforceable, the development and implementation of a set of unique and distinct TS to cover the full scope of the desired SG tube integrity program is judged to involve some risk over a lack of flexibility and balance. More significantly, licensees may or may not elect to adopt the TS program for their SG tube integrity program. In these instances, a lack of uniformity and regulatory consistency would result in the utilization of staff resources for plant specific reviews. The TS approach (in conjunction with a GL) can address the current problems; however, it may not be optimal dependent on the level of resources necessary to review the TS for all PWR licensees.

2.2.8 Rulemaking and Regulatory Guide

When compared both to current plant-specific and alternate generic approaches described above, rulemaking with a supporting regulatory guide containing the performance-criteria was initially viewed as the best approach (based on available information). This was based in part on the capability of the rule to implement a consistent set of regulatory criteria for each plant which allows updating, provides for a standard set of TS, and enhances the ability to ensure uniform compliance with staff requirements.

The objective of the draft SG tube integrity assurance rule would be to provide continued assurance that SG tubes will remain capable of performing their intended safety functions under changing forms of degradation and to provide incentives for utilizing state-of-the-art inspection and repair methods. Rulemaking concerning SG tube integrity would require the development of generic performance-criteria (such as those pertaining to leakage integrity and structural integrity) upon which to ensure the effectiveness of licensee programs. The performance-based criteria would be the subject of a new regulatory guide that would replace RG 1.83 and supplement RG 1.121 which were written many years ago and are in need of updating based on more recent technological improvements in NDE and changing forms of degradation. The objective of the SG rule would be accomplished through the development and implementation by licensees of SG programs that contain appropriate elements important to ensuring defense-in-depth by maintaining a balance of preventive, inspection/repair, and mitigative measures that reflect current operating experience and risk considerations. The SG rule and RG would establish a regulatory framework that enables licensees to develop and implement degradation specific repair criteria without the need for prior NRC review and approval; these degradation specific repair criteria would be described in topical reports and submitted to the NRC for information. Only deviations from NRC guidelines would require staff review and approval. The performance-criteria would be incorporated in a set of standardized TS. Further, resources would be conserved as staff review of licensee programs would not be required when the generic performance-criteria are accepted. However, it should be recognized that the rulemaking approach has the potential for significant resource expenditures associated with the revision of the TS. The amount of resources required depends on the manner in which the rule is implemented (i.e., the degree to which the rule is performance-based).

2.3 Recommendation

On the basis of the foregoing, the staff recommends that a performance-based SG tube integrity rule accompanied by a regulatory guide containing performance-criteria would be the best approach for ensuring SG tube integrity in operating PWR nuclear plants. However, the same arguments apply for imposing the new requirements with a generic letter.

3. Estimation & Evaluation of Values & Impacts

Introduction

The values (changes in public and occupational radiation exposure and changes in property damage) and impacts (costs and savings) for the improvements were evaluated in this analysis. The specific values and impacts that are analyzed are designated "attributes." These attributes include the benefits of avoiding accidents as well as direct consequences of implementing the improvements. The attributes relevant to this analysis are shown in Table 3.1, where they are identified as arising from avoiding accidents or as direct consequences of implementing the proposed rule. The attributes considered in this impact-value analysis are discussed below.

Table 3.1

Attributes Used in the Impact-Value Assessment
V1 = avoided public health risk
V2 = avoided occupational exposure risk associated with accident management and cleanup
V3 = avoided offsite property damage risk
V4 = avoided onsite financial risk due to cleanup and power replacement costs
V5 = decrease (or increase) in routine occupational exposure due to the implementation of the improvements (positive or negative value)
I1 = cost to the NRC covering training, inspection, review, and monitoring associated with the improvements (positive or negative impact)
I2 = direct cost to the licensee to implement the improvements and changes in operating cost (positive or negative impact)

Values

The following four positive values arise if the severe accident radiological release frequency decreases due to implementation of the rule:

- V1 = avoided public health risk (in 1997 dollars; $200 K / person-Sieverts (Sv) conversion used)

- V2 = avoided occupational exposure risk associated with accident management and cleanup (in 1997 dollars; $200 K / person-Sv conversion used)

- V3 = avoided offsite property damage risk (in 1997 dollars)

- V4 = avoided onsite financial risk due to cleanup and power replacement costs (in 1997 dollars)

In addition, there may be a positive (or negative) benefit associated with a decrease (or increase) in the routine occupational exposure to implement the improvements. Improvements in SG programs and activities can affect occupational exposures both positively and negatively. The following is a fifth value used in this analysis:

- V5 = decrease (or increase) in routine occupational exposure due to the implementation of the improvements (positive or negative value) (in 1997 dollars; $200 K / person-Sv conversion used)

Impacts

One impact to licensees and one to the NRC are defined as follows:

- I1 = cost to the NRC covering training, inspection, review, and monitoring associated with the improvements (positive impact) (in 1997 dollars)

- I2 = direct cost to the licensee to implement the improvements and changes in operating cost (positive or negative impact)(in 1997 dollars)

Values and Impacts

The following is the general "Net Value" equation:

NV = V1+V2+V3+V4+V5 - (I1+I2)

A positive value for NV indicates that it is worthwhile, from a value/impact perspective, to proceed with the proposed rule; a negative value indicates that proceeding with the proposed rule would not be cost effective.

Organization of Section 3

Avoided-risk values (V1, V2, V3, and V4) are described in Section 3.2. Section 3.1 supports Section 3.2 by determining the changes in the frequency of radionuclides releases as a result of the rule implementation -- either considering the performance-based rule or the TS-based rule.

The impact assessment of each program element as defined in either the performance-based rule or the TS-based rule is evaluated in Section 3.3 for the industry (I2+V5) and the NRC staff (I1). The individual impacts were derived from the program elements of the SG integrity program (either performance-based rule or the TS-based rule and are delineated in Appendix D.

Finally, in Section 3.4, the "values" and the "impacts" are combined to yield the "Net Values" for the rule variants of interest.

General Approach

The draft SG rule was assessed in its entirety from a value-impact perspective (i.e per 10 CFR 50.109(a)(3)) recognizing that the staff had concluded that all the additional requirements, with the exception of those pertaining to the risk resulting from severe accident-induced SGTR, were supportable (for generic imposition on PWR licensees) based on invoking the compliance exception provisions of 50.109. This perspective was pursued for two basic reasons:

(1) It provides a overall understanding of the draft rule's net value (specifically whether there is substantial additional protection to public health and safety and whether the direct and indirect costs are justified) and this information, particularly the risk reduction and implementation costs, is useful for supporting CRGR review (CRGR is interested in understanding the costs associated with compliance actions even though such actions can be imposed without consideration of cost).

(2) The risk reduction portion could be readily separated from the overall draft SG rule net value assessment and examined on its own merits.

The Net Value equation is basically a comparison of (1) the "Values" in taking a regulatory action, that is, the risk avoided in taking an action to (2) the "Impacts" of taking that regulatory action, that is, the costs to the industry and the NRC of taking that action. The NRC Regulatory Analysis Guidance states that the starting point or base from which the regulatory-action Values and Impacts are determined should not contain any consideration of voluntary actions on the part of the licensees. Only those aspects that are required by the NRC (e.g. current TS) should be considered in the base case. In the analysis performed here, this is the case for the "Impact" part of the Net Value comparison. That is, no credit was given for the considerable voluntary actions taken by the industry to date in calculating the Impacts of the implementation of the rule.

This is not the case for the "Value," or risk avoidance part of the Net Value comparison. The starting point for the risk avoidance part of the analysis assumes a reduction in the STGR frequency due to voluntary actions on the part of the licensees and the ad hoc regulatory approach of the NRC staff. The net result is that the SG tube surveillance and inspection actions currently performed by PWR licensees significantly exceed the minimum requirements of the TS. As such, the staff believes that these voluntary actions have already caused a reduction in the SGTR frequency. It is therefore somewhat of an "apples and oranges" comparison to use the current SGTR frequency on the "Value" side of the equation and then use a cost differential that excludes voluntary actions on the "Impact" side of the equation. This inconsistency was recognized and a sensitivity on differential cost was performed to provide insights as to the more realistic additional costs that PWR licensees would incur due to the additional "compliance" requirements. The results of that sensitivity are presented in Section 4.6.

Two basic cases were considered for determining the risks avoided (or averted) by implementing the proposed rule as well as the "impacts." These are as follows:

- **Rule Case**: This case consists of two variants and shows the potential impact of the rule implementation relative to the base case. The individual impacts (I1 and I2) defined in Appendix D were sorted to correspond to the impact for each rule variant evaluated.

  Rule Variant 1 This variant is based wholly upon the performance-based implementation of the proposed rule provisions. There is no regulatory guide or associated technical specifications. This variant is referred to as performance-based.

  Rule Variant 2 This variant is more prescriptive and involves implementation of guidance and requirements specified in the performance criteria of the draft regulatory guide and associated TS. Thus it can be thought of as "TS-specification based" as compared to "performance based." This variant makes implementation of the TS referenced in the regulatory guide a requirement.

- **Base Case:** Consistent with NRC guidelines for regulatory analysis, the base case reflects the plant operations status prior to rule implementation and does not allow for "voluntary" actions, except as noted.. Its basis lies with the SG TS currently in place for full-power operations.

Three categories of SG tube failure (or rupture) are considered in this regulatory analysis: (1) spontaneous steam generator tube rupture (SGTR) which leads to core damage; (2) SGTR which results from a large differential pressure across the tubes and leads to core damage; and (3) SGTR which is induced from (caused by) a core damage accident (or severe accident) with accompanying high temperature -- the core damage precedes the SGTR.

Terms Used in Regulatory Analysis

Case	refers to pre- and post- rule implementation status of the plant, i.e., the "base case" as "pre-" and the "rule case" as "post-" rule implementation
Rule Variant	refers to the rule alternatives, currently two: Rule Variant 1 is performance-based while Rule Variant 2 is TS-based
Category	refers to different types of SGTR (spontaneous, pressure-induced, severe accident-induced)
Option	refers to the various fixes that are being considered to prevent or mitigate the consequences of the severe accident-induced SGTR. It is assumed that a given fix is the same under both rule variants.

3.1 Risk Analysis

In Section 3.1, the changes in the frequency of radiological release (avoided risk) are evaluated for the two variants to the rule (relative to the base case) and for the three categories of SGTR.

3.1.1 Avoided-Risk Assessment for Category 1 -- Spontaneous SGTR

No reduction of the frequency of spontaneous SGTRs under the proposed regulation is made.

The SG tube rupture frequency has a historic rate of 5×10^{-3} ruptures/reactor year of operation. The target of the new approach is assumed under the rule and under RG X. XX should be a rupture frequency as close to zero as possible. However considering the complexity of the various degradation mechanisms and the multiple variables which influence these mechanisms, this analysis assumed that there would be no significant improvement in the frequency of spontaneous SGTR such that the frequency of Category 1 tube rupture remains at 5×10^{-3} ruptures/reactor-year of operation. Thus, no credit is taken for the "avoided risk" for a decrease in spontaneous SGTRs. This applies to both variants of the rule. If credit was assumed in this analysis, the Net Value, reported in Section 4, would increase.

Considering the spontaneous SGTR (at 5×10^{-3} ruptures/reactor year of operation) as an initiator of core damage events, the value for the large-early release frequency (LERF) was determined to be 1×10^{-6} "large-early release events"/reactor year. This was based on IPE PRA results, NUREG-1150, and other analyses.

Although this analysis does not assign any quantitative risk reduction for rule implementation as it is affected by spontaneous SGTRs, there are qualitative arguments for

improvement. These arguments, broken out by elements of the regulatory guide, are described in Appendix A.

3.1.2 Avoided-Risk Assessment for Category 2 -- Pressure-Induced SGTR

No reduction of the frequency of Pressure-Induced SGTRs under either variant of the proposed regulation is made.

Pressure-Induced SGTRs are caused by a rapid depressurization of the secondary side of a plant at power. This depressurization will result from a MSLB or the failure to close of an atmospheric dump valve or secondary safety valve. The initiating event, for example a MSLB, can result in SGTRs, which, in turn, can result in a core-damage event that bypasses the containment, yielding a severe large-early release accident. The LERF for this category of SGTR was determined to be 3×10^{-6} "large-early release events"/reactor year for the base case. It was also determined that the implementation of the rule will not result in a defensible quantitative reduction in this LERF. Thus, although there are defensible arguments that the SG tube failures could be less -- arguments similar to those for the spontaneous SGTR -- such an assumption for avoided risk from Category 2 SGTRs was not incorporated into this regulatory analysis.

3.1.3 Avoided-Risk Assessment for Category . Severe Accident-Induced SGTR

Methods and Analysis

The staff undertook an example analysis to determine the severe accident risk of tube rupture as a consequence of a core damage accident. The Surry plant, a three-loop Westinghouse PWR design, was used as the basis for the analysis. This section outlines the methods used for the staff calculation to estimate containment-bypass probability associated with temperature-induced tube rupture during a severe accident. In this study, a "high-risk" PWR was assessed, as well as a "representative" PWR. The detailed analysis is documented in Draft NUREG-1570.

Temperature-induced tube failures could occur when there are elevated differential pressures across the flawed SG tubes in conjunction with high tube temperatures, occurring during a core damage accident. In general, the requisite conditions for temperature-induced tube failure are as follows:

- dry SG secondary,
- high or intermediate primary system pressure, and
- low SG secondary side pressure.

Events in which core damage occurs with the primary system at high pressure and the secondary side dry and depressurized are generally considered to pose the greatest threat of temperature-induced tube rupture. However, analyses performed by the NRC staff indicate

that events with the primary system at intermediate pressures may also pose an appreciable threat to tube structural integrity. The accident sequences posing the greatest threat of temperature-induced tube failure and their expected frequencies are discussed in the following.

The following discussion focuses on the accident progression following core damage with a high-pressure RCS and a dry secondary. The structure of the accident progression possibilities is displayed in Figure 3-1 which shows the accident progression event tree (APET) with split fractions for the "representative" PWR. The following provides a selected discussion of important top events of the APET.

Frequency of High Pressure Core Melt With Depressurized SG(s)

Note that the following discussion comes from NUREG-1570. The reader should refer to NUREG-1570 for the most recent discussion.

Station blackout (SBO) sequences account for the majority of events in which core damage occurs with the primary system at high pressure and the secondary side dry and depressurized. In a typical SBO, steam generator dryout results in loss of decay heat removal via the SGs, and eventual loss of RCS inventory and uncovery of the core. As core damage progresses, RCS components and SG tube temperatures increase as substantial amounts of energy are transported from the core region to other parts of the RCS. The impact on the analysis of stuck open pressurizer power operated relief valves (PORVs) or safety valves (SVs), reactor coolant pump (RCP) seal LOCAs, operation of SG atmospheric dump valves (ADVs) or main steam safety valves (MSSVs), and longer term depressurization of the secondary side due to leakage from SG isolation valves were considered.

The APET developed by the staff (Figure 3-1) provides a means of characterizing the various primary/secondary system conditions that could challenge the tubes. It further aids in evaluating the core degradation process and resulting pressure/temperature challenges for each condition, and in quantifying the probability that tube integrity will be maintained under these challenges. The result of this assessment is an overall estimate of the probabilities of pressure- and temperature-induced failure of SG tubes and containment-bypass frequency for these severe accident challenges.

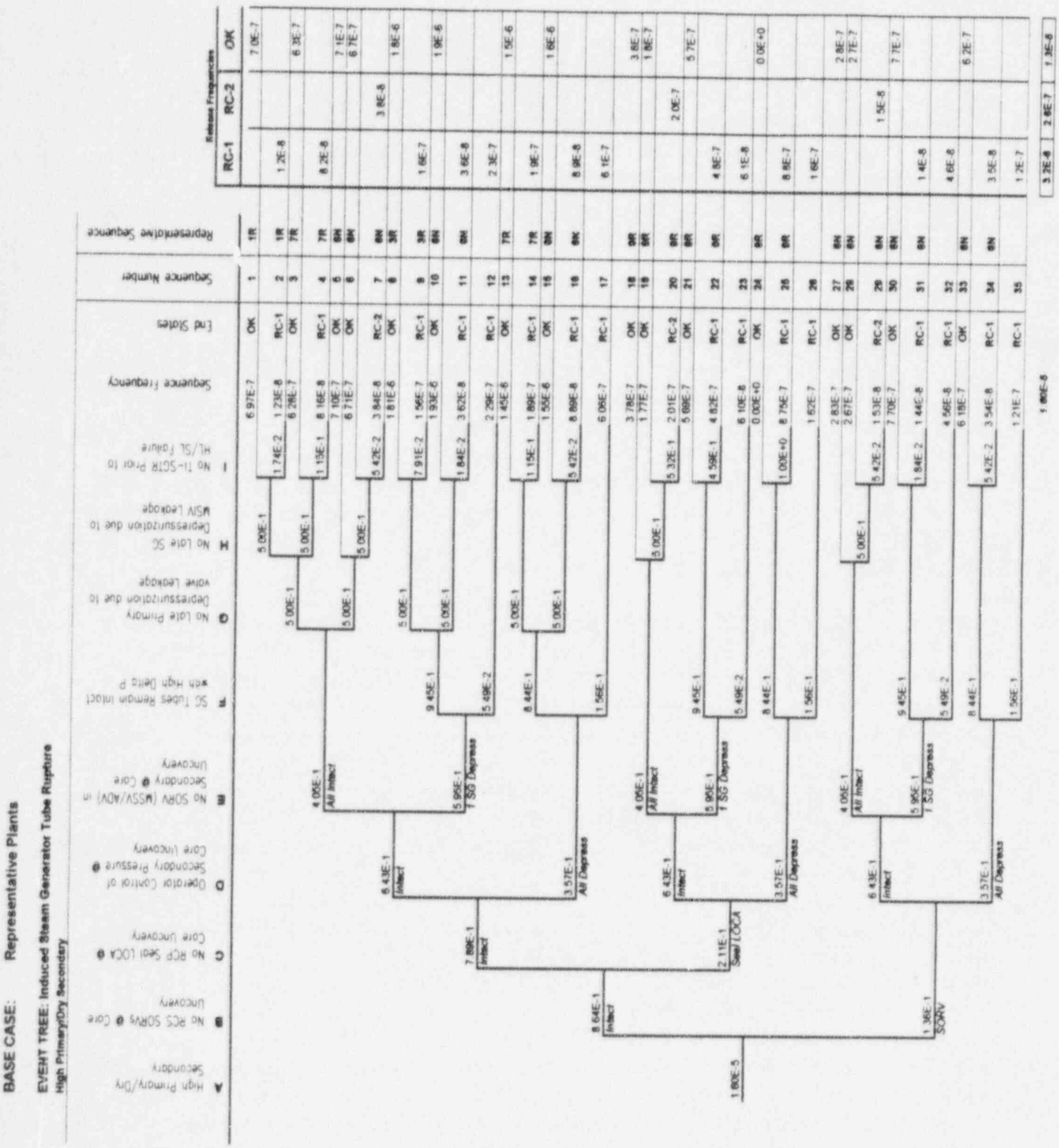


Figure 3-1 Accident Progression Event Tree

The frequency of high RCS pressure/dry SG sequences used as the input to the APET was derived from the NUREG-1150 plant damage state (PDS) information. The results of the IPE database search were evaluated further to identify (1) any major differences in sequences contributing to core damage with high primary pressure/dry SGs, or (2) any significant design biases. Two approaches were taken. Based on NUREG-1150, the high/dry frequency for Surry is 1.6E-5 per reactor year, a value very close to the mean IPE-based high/dry frequency for 3-loop Westinghouse plants. Furthermore, the NUREG-1150 value for Surry seems to envelope most (all but 9) of the plants, and is within a factor of 4 of the highest IPE high/dry frequency.

The database search confirms that the sequences contributing to core damage with high primary system pressure and dry SGs are dominated by station blackout events, with an additional contribution from other transient events. This result is consistent with the sequence characterization based on the NUREG-1150 PDS information. Furthermore, comparison of high/dry core damage frequency across NSSS designs does not reveal any strong design biases. The staff concluded that the frequency of core damage with high primary system pressure and dry SGs from the Surry NUREG-1150 analysis is reasonably representative of the population of Westinghouse and CE plants, and has based its example risk assessment on this value, namely 1.6E-5 per reactor year (Top Event A of APET).

<u>Potential for RCS Depressurization (Top Events B, C, & G)</u>

Transient events such as SBO generally proceed to core damage with the primary system at or near the PORV or SV setpoint. However, failure of pressurizer relief valves to reclose/reseat or RCP seal LOCAs could result in a partially depressurized RCS at the time of core damage. The extent of depressurization is sequence- and plant-specific and dependent on such factors as the timing and leak area associated with the valve failure/seal LOCA, and accumulator injection setpoints. Although a lower RCS pressure at the time of core damage would reduce the challenge to SG tube structural integrity, in certain scenarios this reduction could be offset by rapid repressurization and heating of SG tubes that may occur during the accumulator injection phase of the accident, or the effects if possible cold leg loop seal clearing.

The fraction of high primary pressure/dry SG events with a stuck-open PORV for Surry, 14 percent, is in general agreement with the probability predicted by a separate assessment considering actual valve demands in conjunction with valve failure rates from Accident Sequence Evaluation Program. The staff acknowledges that a higher per-demand valve failure rate during the boildown phase, such as predicted by the EPRI cumulative damage model, and a higher fraction of sequences with a stuck-open PORV may be appropriate. However, the staff believes that the uncertainty in the probability of early failure of the PORV/SV is adequately captured in the later APET branch (Top Event G), and that additional justification would be needed to support the use of a substantially higher probability for early failure of the PORV/SV. Therefore, a relatively high value (0.5) has been assigned to the probability that the PORV does not reclose later in the event during core degradation.

The percentage of events with an RCP seal LOCA for Surry, 18 percent, is in general agreement with the underlying modeling assumptions regarding seal LOCA. Differences can be attributed to a combination of factors, including plant-to-plant differences that influence the composition of the high primary pressure/dry SG sequences. Due to the high tube failure potential for the RCP seal LOCA case, the staff is investigating the basis for the seal LOCA modeling used for Surry. (The high tube failure potential is due to the clearing of the cold-leg-loop-seal when the RCP seal LOCA occurs, thus allowing for RCS natural circulation flow and accompanying high SG tube temperatures.) Also, design- and plant-specific factors affecting the impact of seal LOCA on tube conditions are being evaluated to confirm the magnitude of the risk contribution attributed to the seal LOCA case.

Key differences between Surry, other Westinghouse designs, and CE designs that could introduce significant differences in the accident sequence progression and event tree structure and quantification are highlighted. This includes comparison and consideration of potential differences in the following:

- severe accident progression, thermal-hydraulic response, and RCS/SG creep failure behavior for unflawed tubes,
- maintenance of the cold leg loop seal,
- plant capabilities and operator actions to depressurize,
- pressurizer PORV/SRV failure probabilities,
- SG ADV/SV failure probabilities,
- probability and magnitude of seal LOCAs, and
- SG degradation mechanisms and locations, and associated flaw distributions.

Thermally-Induced SGTR (Top Event I)

The ninth top event in the APET (The first top event in the APET is the "initiating event" -- the frequency of high primary/dry secondary sequences with core damage) addresses the probability that thermally-induced failure of SG tubes occurs prior to any other breach of the RCS pressure boundary. The probability that a thermally-induced SGTR occurs depends on the temperature and pressure histories throughout the RCS for each APET branch, which in effect defines the set of thermal and structural loads for the RCS components and SG tubes for the spectrum of severe accidents. The distribution of flaws within the SG tubes is a critical input parameter influencing this top event, and one which distinguishes this work from previous analyses.

In the present study, the staff has estimated the probability of a TI-SGTR separately for each APET branch. The process involves the following major steps:

1. Define the RCS and SG pressure-temperature history for each APET branch based on thermal-hydraulic analyses that sufficiently represent the sequences addressed by each branch,

2. Estimate the representative SG flaw distribution for the plant of interest,

3. For each APET branch and flaw distribution, determine the time to failure for major RCS components subject to thermal failure (hot leg and surge line) based on the pressure-temperature profile and the structural failure criteria, and

4. Estimate the probability of TI-SGTR based on the relative times to failure of RCS components, and judgments regarding the uncertainties and margins in these estimates.

3.1.4 Further Discussion of SGTRs and Implications.

Conditional Failure Probabilities for Steam Generator Tubes

Along with RCS temperatures and pressures, the SCDAP/RELAP5 code also calculates a creep damage index as a function of time for components susceptible to temperature induced failure; the hot legs, pressurizer surge line, and the SG tubes. In previous studies, which did not consider the effects of flaws in tubes, the hot leg or surge line were assumed to fail prior to the tubes. However, the presence of degradation in the SG tubes will cause earlier failures. In addition, the variability of the component dimensions and material properties will produce a probability distribution for the time of failure for each component. In order to estimate the probability that SG tubes will be the first reactor coolant pressure boundary failure during a particular thermal-hydraulic sequence, it is necessary to consider the probability distributions as a function of time for each component of interest.

Stand-alone computer codes were developed to compute creep damage indices for certain components, based on the time-dependent temperature and differential pressure outputs generated by SCDAP/RELAP5. The results of these codes were initially verified against the creep damage index results from SCDAP/RELAP5, using the same component dimensions and material properties used by SCDAP/RELAP5. The creep damage calculations in the stand-alone codes were then extended to cover a variety of component dimensions, material properties and, for SG tubes, the existence of various sizes of flaws.

The CRAB code generates the creep damage index for the surge line or hot leg, based on a single value of the Larsen-Miller creep damage parameter and a specific set of component dimensions. Larsen-Miller failure modeling was used for consistency, since it is applied in SCDAP/RELAP5. For each thermal-hydraulic case (corresponding to an event tree sequence), the 5, 50, and 95 percentile values of the Larsen-Miller parameter correlation were used to generate failure times of the surge line (or the hot leg, if it was predicted to

fail before the surge line). The resulting times are considered to be associated with probabilities of 95, 50, and 5 percent that component has not yet failed at that point in time. A smooth function in time was established by fitting these three values with normal distributions. Because the temperature of the components of concern is increasing rapidly at their times of failure, the later failure times are much closer to the 50 percent probability time than are the earlier times. This behavior was accommodated by fitting the times earlier than 50 percent with one normal distribution and the times later than 50 percent with a different normal distribution. Although not considered to be a very precise fit, the results are believed to be adequate to provide a probability value for surge line (or hot leg) failure prior to the time that a particular flawed tube is calculated to fail.

The CRPROB code generates estimates of the probability that specific SG tube flaws will fail prior to the failure of the surge line or hot leg. Probability estimates are produced for a specified set of flaws (length and depth) for each thermal-hydraulic case. The CRPROB code uses Monte Carlo methodology to combine the effects of tube diameter and thickness variability, tube Larsen-Miller creep behavior variability, and the range of crack lengths and depths that are binned together in the flaw population size distribution for a representative plant.

Crack lengths are separated into two bins (1) those that are long enough to fail as ruptures at the pressure differentials associated with depressurization of the secondary side of a stream generator at normal operating temperatures, and (2) those that would not fail as ruptures under the preceding conditions, but would rupture when the temperatures were elevated by core oxidation during severe accident sequences. For each crack dimension bin in the flaw population distribution, probability values were calculated for 1000 randomly selected combinations of tube diameter, thickness, Larsen-Miller correlation, and crack size. The CRPROB output is the average of the probabilities for each flaw size bin.

The conditional probability of tube rupture during a specific thermal-hydraulic sequence is calculated by combining a flaw population size distribution with the rupture probability information for that sequence. Because the flaw size distributions vary greatly among plants and because different size cracks are poorly distinguished by currently available eddy current inspection techniques, three different flaw size distributions were developed and examined. For a specific distribution and specific thermal-hydraulic case, the flaws in each bin are first considered to be subject to the appropriate differential pressure at normal operating temperatures, and the probability of rupture due to limit load analysis is calculated. The results for each bin are combined to produce the probability that one or more flaws will rupture due to increased differential pressure that occurs early in the sequence. This result is used in an appropriate reduction in the "initiating event" frequency as the starting point for the event tree evaluation. Flaws that would rupture under these conditions are removed from the distribution, and the remaining flaws are considered to be exposed to the higher temperature conditions at the appropriate differential pressure for the thermal-hydraulic sequence. Again the results from each bin are combined to produce the probability that one

or more flaws will rupture during the core oxidation phase of the sequence. This result is then used in the event tree evaluation.

Containment-Bypass Frequency

The complete evaluation of the accident progression event tree for a single flaw distribution requires the analysis described above to be conducted for each thermal-hydraulic sequence that is associated with a path through the event tree. The event tree is evaluated separately for each flaw population size distribution as a sensitivity study on that input.

Implicit in these analyses are assumptions about the progression of the thermal-hydraulic sequence once the reactor coolant pressure boundary (RCPB) has been breached. If the first breach of the RCPB is rupture of the surge line or hot leg, it is assumed that the reactor coolant system (RCS) is depressurized rapidly enough to preclude subsequent rupture of SG tubes. If the first failure of the RCPB is a SG tube, this is assumed to result in a containment-bypass type release. It was not considered feasible to extend the thermal-hydraulic analysis to determine whether enough tubes would rupture to sufficiently depressurize the RCS that it would preclude subsequent failure of the surge line or hot leg. If the surge line or hot leg did fail after only one or two SG tubes failed, it would greatly diminish the force driving the release of radioactive materials, substantially reducing the threat to the public. However, the ability to model the effects of a single tube rupture on the adjacent tubes was not considered sufficiently accurate to predict the number of tubes that would ultimately rupture in a sequence. Therefore, all tube ruptures were considered to result in substantial bypass of the containment. This assumption creates an unknown degree of conservatism in the estimates for the frequency of bypass type releases.

The results of the staff example analysis for Surry indicate that containment-bypass frequencies could lie in the range of mid E-6 per reactor year.

A high confidence analysis to assess SG tube performance associated with the most probable high pressure core damage sequence for the plant would use state-of-the art analysis tools and available experimental information to: (a) determine events of concern for SG tube thermal challenge, (b) predict RCS thermal-hydraulic conditions, (c) predict high temperature RCS component performance, and (d) estimate conditional SG tube failure probability.

Areas Needing Further Evaluation

The example analysis revealed a number of areas of uncertainty and variability involved in estimating tube failure probability associated with core damage events. As stated in the

Regulatory Guide, further analysis should address uncertainties and variabilities in at least the following areas:

a. Data for Event Trees: To arrive at a tube failure estimate, the staff used an event tree representing major progressions starting from the high-pressure core damage, dry SG condition.

- Failure frequencies for important pressure relief components in the RCS and secondary systems (PORVs, MSSVs, ADVs) are not well known.

- Failure frequency of reactor coolant pump seals and the magnitude of the resulting leak might be design-specific, could be better defined.

- Plant-specific configurations and procedures will affect the structure and split fractions composing the event tree.

b. Thermal-Hydraulic Modeling:

- The range of maximum tube temperature and associated pressure expected during the event and the associated uncertainty in the prediction should be determined. An alternative is to apply conservative estimates to account for the modeling and calculational uncertainties.

- Associated with the prediction of maximum tube temperature and pressure, the rate of heating for RCS components is important since it affects creep failure potential. Staff analysis estimates the relative time to failure for tubes, surge line, and hot leg, which could vary under different heating rates. Other RCS components could be included in such an analysis.

- Several factors could significantly influence thermal-hydraulic performance, such as RCS piping configuration, RCS depressurization capability, secondary system pressure integrity, core configuration, SG design, and emergency operating procedures. These should be explicitly accounted for in a plant-specific analysis.

c. Tube Performance Model:

- Material factors which could affect prediction of creep failure for tubes and other RCS components should be based on experimental information.

- Other failure modes should be considered, such as the potential for propagation to gross tube failure associated with tube leakage under high pressure core damage conditions.

- The model should be shown to apply to thermal-hydraulic conditions predicted for the events of concern.

- The staff analysis included a model of the effect of axial cracks on high temperature tube performance. A similar characterization accounting for the particular degradation considered should be included in a plant-specific analysis.

d. Reactor Coolant Pressure Boundary Weak Points:

- The staff analysis estimated time to thermal failure for surge line and hot leg relative to the SG tubes. Other locations in the RCS may be threatened with thermal failure and could influence the potential for tube thermal failure.

e. Flaw Distribution:

- The estimated SG flaw distribution used in the final step of estimating tube failure frequency can vary significantly depending on plant tube degradation experience.

- The staff estimated a flaw distribution based on flaw size. This is difficult to accomplish on a plant-specific basis given the current state-of-the art in tube inspection capability. Other characterizations of flaw distributions may be applied, but their integration into the tube performance model must be sufficiently defined.

The uncertainty of the factors listed above could be determined separately and required to meet some defined level, or the overall tube failure probability estimate should be shown to be at a defined level of confidence. For the purposes of this regulatory analysis, the uncertainties discussed above have been incorporated into an uncertainty analysis which is discussed in Section 4.5.

3.1.5 APET Quantification

The avoided-risk assessment for severe accident-induced SGTR proceeded using the APET (Figure 3-1) and the following values for the top events:

Table 3.2 APET Quantification

Top Event Description	top event coding	Base Case Split Fractions: Low Risk Plant	Representative Plants	High Risk Plants	Rule Case Sensitivities: 1 No Late SG Depress	2 Lower Early SG Depress	3 Case 1 and 2	4 Perfect Late Primary D	5 No Late Primary D	6 No RCP Seal LOCA	7 Temp + 70K
High Primary/Dry Secondary	**A1**	5.00E-7	1.60E-5	1.00E-4	na	na	na	na	na	na	na
No RCS SORVs @ Core Uncovery	**B1**	9.80E-1	1.36E-1	1.36E-1	na	na	na	na	na	na	na
No RCP Seal LOCA @ Core Uncovery	**C1**	0.00E+0	2.11E-1	5.79E-1	na	na	na	na	na	**0.00E+0**	na
Operator Control of Secondary Pressure @ Core Uncovery	**D1**	1.87E-2	3.57E-1	3.57E-1	na	1.87E-2	1.87E-2	na	na	na	na
	D2	1.87E-2	3.57E-1	3.57E-1	na	1.87E-2	1.87E-2	na	na	na	na
	D3	1.87E-2	3.57E-1	3.57E-1	na	1.87E-2	1.87E-2	na	na	na	na
No SORV (MSSV/ADV) in Secondary @ Core Uncovery	**E1**	3.54E-2	5.95E-1	5.95E-1	na	3.54E-2	3.54E-2	na	na	na	na
	E2	3.54E-2	5.95E-1	5.95E-1	na	3.54E-2	3.54E-2	na	na	na	na
	E3	3.54E-2	5.95E-1	5.95E-1	na	3.54E-2	3.54E-2	na	na	na	na
SG Tubes Remain Intact with High Delta P	**F1**	2.52E-2	5.49E-2	1.47E-1	**5.00E-2**	5.00E-2	5.00E-2	5.00E-2	5.00E-2	5.00E-2	5.00E-2
	F2	7.37E-2	1.56E-1	3.80E-1	1.43E-1	1.43E-1	1.43E-1	1.43E-1	1.43E-1	1.43E-1	1.43E-1
	F3	2.52E-2	5.49E-2	1.47E-1	**5.00E-2**	5.00E-2	5.00E-2	5.00E-2	5.00E-2	5.00E-2	5.00E-2
	F4	7.37E-2	1.56E-1	3.80E-1	1.43E-1	1.43E-1	1.43E-1	1.43E-1	1.43E-1	1.43E-1	1.43E-1
	F5	2.52E-2	5.49E-2	1.47E-1	**5.00E-2**	5.00E-2	5.00E-2	5.00E-2	5.00E-2	5.00E-2	5.00E-2
	F6	7.37E-2	1.56E-1	3.80E-1	1.43E-1	1.43E-1	1.43E-1	1.43E-1	1.43E-1	1.43E-1	1.43E-1
No Late Primary Depressurization due to valve Leakage	**G1**	5.00E-1	5.00E-1	5.00E-1	na	na	na	**1.00E+0**	**0.00E+0**	na	na
	G2	5.00E-1	5.00E-1	5.00E-1	na	na	na	1.00E+0	0.00E+0	na	na
	G3	5.00E-1	5.00E-1	5.00E-1	na	na	na	1.00E+0	0.00E+0	na	na
No Late SG Depressurization due to MSIV Leakage	**H1**	5.00E-1	5.00E-1	5.00E-1	**0.00E+0**	na	**0.00E+0**	na	na	na	na
	H2	5.00E-1	5.00E-1	5.00E-1	0.00E+0	na	0.00E+0	na	na	na	na
	H3	5.00E-1	5.00E-1	5.00E-1	0.00E+0	na	0.00E+0	na	na	na	na
	H4	5.00E-1	5.00E-1	5.00E-1	0.00E+0	na	0.00E+0	na	na	na	na
No TI-SGTR Prior to HL/SL Failure	**I1**	1.74E-2	1.74E-2	4.71E-2	na	na	na	na	na	na	2.43E-2
	I2	1.15E-1	1.15E-1	2.81E-1	na	na	na	na	na	na	3.42E-1
	I3	5.42E-2	5.42E-2	1.40E-1	na	na	na	na	na	na	1.04E-1
	I4	7.91E-2	7.91E-2	2.00E-1	na	na	na	na	na	na	2.44E-1
	I5	1.84E-2	1.84E-2	4.90E-2	na	na	na	na	na	na	3.58E-2
	I6	1.15E-1	1.15E-1	2.81E-1	na	na	na	na	na	na	3.42E-1
	I7	5.42E-2	5.42E-2	1.40E-1	na	na	na	na	na	na	1.04E-1
	I8	5.32E-1	5.32E-1	6.91E-1	na	na	na	na	na	na	6.46E-1
	I9	4.59E-1	4.59E-1	6.31E-1	na	na	na	na	na	na	5.82E-1
	I10	1.00E+0	1.00E+0	1.00E+0	na	na	na	na	na	na	1.00E+0
	I11	5.42E-2	5.42E-2	1.40E-1	na	na	na	na	na	na	1.04E-1
	I12	1.84E-2	1.84E-2	4.90E-2	na	na	na	na	na	na	3.58E-2
	I13	5.42E-2	5.42E-2	1.40E-1	na	na	na	na	na	na	1.04E-1

na = no change from Base Case values

The determination of these top events is described in Draft NUREG-1570. In addition to the "Base Case" input data, the input data for several rule options and the sensitivity studies are also presented in Table 3.2. The option chosen for further consideration in the regulatory analysis as the rule case for determining the avoided risk is the "Option 3," which is a combination of Options 1 & 2. Option 3 represents the largest ΔLERF reduction from the APET sensitivities performed and as such it was an appropriate case to use to scope out the feasibility of imposing risk requirements on PWR licensees (i.e. it would yield the largest net value in terms of averted risk). The options 1, 2, 3, 4, 5, 6 and 7 are described and addressed further in section 4.6.

Using the values listed in Table 3.2, the CDFs, the LERFs, the ΔCDFs and the ΔLERFs for Category 3 SGTRs are calculated as follows:

Table 3.3 Risk Results: "Representative PWRs"

	Base Case: No voluntary actions	**Rule Variant 1:** Performance based case	**Rule Variant 2**: Tech. Spec. based case
CDFs	1.6xE-5/r-y	1.6xE-5/r-y	1.6xE-5/r-y
ΔCDFs relative to the base case		0.0	0.0
LERFs	3.2xE-6/r-y	2.8xE-7/r-y	2.8xE-7/r-y
ΔLERFs relative to the base case		2.9xE-6/r-y	2.9xE-6/r-y

Note: LERF= Large Early Release Frequency or "RC-1"

These results are discussed in more detail in section 4.3.

3.2 Estimation Of Values

In this section, the Values V1, V2, V3, and V4 are first discussed in general. Then specific application is made to the two rule variants under consideration.

3.2.1 Avoided Public Health Risk (V1) for Each Plant

The CDFs and the LERFs (containment-bypass release) calculated for the base case and the variants of the rule cases in Section 3.1 are assumed applicable to all relevant PWRs.

In regulatory analysis, for any given plant i, one estimate of V1 is obtained:

$V1_i^{B\text{-}R}$ = avoided public health risk (1997 dollars) associated with moving from base case regime to rule case regime for plant i

The event-tree analysis yields the incremental change in containment or containment-bypass release frequencies associated with the two different regimes.

When considering the base case versus the rule case for PWR type plants, we have:

$\Delta f\ (RC\text{-}1\ _{PWR}^{B\text{-}R})$ = reduction in frequency of containment or containment-bypass release category 1 (large release) for a PWR type plant moving from the base case regime to the rule case regime

$\Delta f\ (RC\text{-}2\ _{PWR}^{B\text{-}R})$ = reduction in frequency of containment or containment- bypass release category 2 (medium release) for a PWR type plant moving from the base case regime to the rule case regime

$\Delta f\ (RC\text{-}3\ _{PWR}^{B\text{-}R})$ = reduction in frequency of containment or containment- bypass release category 3 (small release) for a PWR type plant moving from the base case regime to the rule case regime

Next the $\Delta f\ (RC\text{-}1\ _{PWR}^{B\text{-}R})$, $\Delta f\ (RC\text{-}2\ _{PWR}^{B\text{-}R})$, and $\Delta f\ (RC\text{-}3\ _{PWR}^{B\text{-}R})$ are translated into annual per-plant reduction in public dose consequences (person-Sv) to obtain the monetary value of each plant reduction in public dose based on years remaining until end of plant life.

The source term RC-1 type release estimate of 2.0E04 person-Sv for Surry was applied to each individual plant by adjusting it for power level (radionuclide inventory) and location (siting). For a nuclear power plant i, we have:

P_i = thermal power (MW) associated with nuclear plant,

$SST1_i$ = conditional latent cancer fatalities for a large release accident during full power operation for a standard 3500 MW (thermal) PWR at the site where plant i is located(accident source terms for all U.S. sites are tabulated in Table C-1, NUREG/CR-2239)

Now *pd* ($RC\text{-}1_i$), the conditional public dose (person-Sv) associated with RC-1-type releases for plant i, can be obtained from the following:

$$pd(RC\text{-}1_i) = pd(RC\text{-}1_{Surry}) * P_i / P_{Surry} * SST1_i / SST1_{Surry}$$

where:

pd ($RC\text{-}1_{Surry}$) = 2.0E4 person-Sv

P_i / P_{Surry} = source term scaling factor

$SST1_i / SST1_{Surry}$ = siting scaling factor

In this study, the following is assumed:

pd ($RC\text{-}2_i$) = 0.1 x pd ($RC\text{-}1_i$), and

pd ($RC\text{-}3_i$) = 0.001 x pd ($RC\text{-}1_i$).

The annual per-plant reduction in public dose consequences (person-Sv) for RC-1 type releases is as follows:

$$RD_{annual\ person\text{-}Sv}(RC\text{-}1_i) = \Delta f(RC\text{-}1_{B\text{-}R\ PWR}) \times pd(RC\text{-}1_i)$$

The annual per-plant reduction in public dose can be converted to the monetary equivalent (1997 dollars) by assuming \$200K for a person-Sv (\$2,000 for a person-rem.

$$RD_{annual\ 1997\text{-}dollars}(RC\text{-}1_i) = \Delta f(RC\text{-}1_{B\text{-}R\ PWR}) \times pd(RC\text{-}1_i) \text{ X } \$200K$$

The avoided public health risk associated with moving from base case regime to rule case regime for the RC-1 type release for plant i is as follows:

$$V1^{B\text{-}R}_{RC\text{-}1i} = RD_{annual\ 1997\text{-}dollars}(RC\text{-}1_i)\ 1\text{-}\exp(-rt_i)/r$$

where,

r = real discount rate (as a fraction, not a percentage)
t_i = years remaining until end of the plant i life

Similar equations were derived for $V1^{B\text{-}R}_{RC\text{-}2i}$ and $V1^{B\text{-}R}_{RC\text{-}3i}$

The total avoided public health risk associated with moving from base case regime to rule case regime for all RC type releases (i.e., RC-1, RC-2, and RC-3) for plant i is as follows:

$$V1_i^{B\text{-}R} = V1^{B\text{-}R}{}_{RC\text{-}1i} + V1^{B\text{-}R}{}_{RC\text{-}2i} + V1^{B\text{-}R}{}_{RC\text{-}3i}$$

As an example, consider Arkansas Nuclear 2. We have:

$P_{\text{Arkansas Nuclear 2}}$ = 2815 MW (thermal)

$SST1_{\text{Arkansas Nuclear 2}}$ = 950 cancer fatalities

Using the following parameters:

P_{Surry} = 2441 MW (thermal) and

$SST1_{\text{Surry}}$ = 1700 cancer fatalities,

the conditional public dose is obtained:

pd(RC-1 $_{\text{Arkansas}}$) = 2.0E4 x 2815/2441 x 950/1700 = 1.3E4 person-Sv.

This means that, given a large release accident (RC-1) during a SGTR of Arkansas Nuclear 1, the dose received by the public is 1.3E4 person-Sv.

pd(RC-2 $_{\text{Arkansas}}$) = 0.1 x 1.3E4 = 1.3E3 person-Sv

pd(RC-3 $_{\text{Arkansas}}$) = 0.001 x 1.3E4 = 1.3E1 person-Sv

Using as an example of numerical results from Table 3.3:

Δf (RC-1 $^{B\text{-}R}{}_{PWR}$) = 2.9xE-6/r-y

Δf (RC-2 $_{B\text{-}R\ PWR}$) = 0

Δf (RC-3 $_{B\text{-}R\ PWR}$) = 0

Now the annual dose reduction for each release category is as follows:

$RD_{\text{annual person-Sv}}$ ($RC\text{-}1_{\text{Arkansas}}$) = 2.9 E-6 x 1.3E4 = 3.8E-2 person-Sv/yr

$RD_{\text{annual person-Sv}}$ ($RC\text{-}2_{\text{Arkansas}}$) = 0 x 1.3E3 = 0 person-Sv/yr

$RD_{\text{annual person-Sv}}$ ($RC\text{-}3_{\text{Arkansas}}$) = 0 x 1.3E1 = 0 person-Sv/yr

Arkansas Nuclear 2 was licensed in 1978. Assuming 1997 to be the year when the rule goes into effect, there will be 21 years remaining of the life of the plant based on lifetime of 40 years. Using a discount rate of seven percent, we have:

$[1\text{-exp } \{-(0.07)(21)\}] / 0.07 = 11.0$

$V1^{B\text{-}R}_{RC\text{-}1\ \text{Arkansas}}$ = \$200K x 3.8E-2 x 11.0 = \$84,000

$V1^{B\text{-}R}_{RC\text{-}2\ \text{Arkansas}}$ = \$200K x 0 x 11.0 = \$0

$V1^{B\text{-}R}_{RC\text{-}3\ \text{Arkansas}}$ = \$200K x 0 x 11.0 = \$0

$V1^{B\text{-}R}_{\text{Arkansas}}$ = \$84,000 + \$0 + \$0 = \$84,000

Each unit at each site is addressed in this manner. The assumptions and criteria described above are applied to calculate the avoided public health risks associated with the modifications.

3.2.2 Avoided Occupational Health Risk (1997 Dollars) (V2)

Estimation of avoided on-site consequences depends on core-damage frequency reductions and accompanying containment-bypass reductions, but not on assumptions about public dose. The occupational exposure consists of immediate and long-term components.

The number of personnel on-site during full power operation typically ranges in the hundreds and, as reported in NUREG-1410, evacuation is not assured. The potential exists for an immediate high dose to on-site personnel. Despite this, we have not included this potential effect in its impact-value assessment because of the large uncertainty involving personnel movements.

Long-term occupational exposure occurs when cleanup and recovery take place beyond work immediately associated with the accident. The value used as an estimate for this exposure was based on a study of decommissioning a reference light-water reactor following a major LOCA in which the emergency core cooling system was delayed in starting. All fuel cladding was assumed to rupture, causing significant fuel melting and

core damage. It was also assumed that the containment building was extensively contaminated, and that the auxiliary building was contaminated too. The estimated occupational radiation dose from cleanup and recovery was 200 person-Sv. For purposes of impact-value analysis, the staff assumed the 200 person-Sv appropriate for the Surry plant for RC-3, 400 person-Sv for RC-2 and 600 person-Sv for RC-1. Values at all other plants were adjusted relative to these values based on the plant's power level. The conversion to 1997 dollars, assuming $200K/person-Sv, is the same as described under Section 3.2.1 for V1.

3.2.3 Avoided Off-Site Damage to Property (1997 dollars) (V3)

Off-site property loss is one of the major value categories for safety-related issues. In severe accidents, property damage off-site can exceed damage on-site. Public property damage costs, V3, were calculated using the analysis similar to that for V1, described in Section 3.2.1. Only the differences between the V1 and V3 values are described here.

Scaled results for property damage costs, given a radionuclide release from the containment (approximating a containment-bypass), were obtained from NUREG/CR-2723. This study reported off-site property costs for accidents at 91 U.S. sites with licensed reactors or construction permits. These costs were based on results obtained using the computer code CRAC2. The upper and lower bound estimates of the scaled damage costs were values from Indian Point Unit 2 and Maine Yankee, respectively. These values were updated to 1997 dollars using an annual inflation rate of 5 percent. A public property damage cost of $1,600M per large release (RC-1) for Surry at the Surry site was assumed ($160M for RC-2 and $1.6M for RC-3) and the value adjusted for each other plant based on that particular plant's power level and site characteristics.

These off-site property damage costs were discounted at a seven percent rate for each year after 1997, when the risk reductions were assumed to begin.

3.2.4 Avoided On-Site Power Replacement and Cleanup (1997 Dollars) (V4)

Replacement power costs were derived by assuming the replacement power costs determined in NUREG/CR-4627, Rev. 1 and adjusting these figures, established in 1988, to 1997 by assuming a five percent inflation rate. For the damaged plant, the amount of time for replacement power is the remaining life of the plant with costs adjusted to 1997 dollars assuming a seven percent discount rate. For sites with more than one plant, it is assumed that the undamaged plant(s) would be shut down for 2 years after the accident; thus replacement power would also be needed for the undamaged plant(s).

Cost estimates for cleanup were obtained from a study which estimated the cost of a major LOCA in which emergency core cooling was assumed to be delayed. In that study, it was assumed that the cleanup activities would take 10 years to complete. Over the 10-year period, the cost of cleanup was estimated to be $373M per event. The on-site consequences were limited to the containment and auxiliary buildings. Thus, this value is

assumed for the RC-3 release. For the RC-2 and especially for the RC-1 releases, there would be more widespread contamination on-site. Consequently, this value was doubled for RC-2 and tripled for RC-1. In addition, the "$373M" was adjusted for inflation (5%) bringing it from its 1983 value to $739M as a 1997 estimate.

Cleanup costs were added to the power replacement cost to get total costs. These total costs were discounted at seven percent for each year after 1997, when the LERF reductions were assumed to begin. The total yearly cleanup and power replacement costs, given core damage, were then expressed in 1997 dollars.

3.2.5 Routine Occupational Health Risk (Person-Sv) (V5)

For routine occupational health risk (V5), the following were assumed:

- Rule implementation will allow for a reduction in routine occupational health risk (a positive "V5") for some rule-related actions.

- Rule implementation will result in an increase in routine occupational health risk (a negative "V5") for other rule-related actions.

- The best-estimate value for the avoided routine occupational health risk (the sum of the reductions and the increases) is consistent with the impacts described in Section 3.3.

- In Table 3.2, aspects of routine occupational health risk are listed. Note that both one-time exposures and per outage exposures are considered.

Table 3.4

Summary of Reductions in Routine Occupational Health Risk : Industry

ID (see Sec. 3.3 for definition)	DESCRIPTION	Δ ONE TIME Dose, Sv (values are place-holders)	Δ CONTINUOUS Dose, Sv/r yr (values are place-holders)
Δ c-1-1	Tube Inspections; More Inspection Time	Not Applicable	- 0.03
Δ c-1-2	Tube Inspections; NDE Technique Performance Demonstration Protocol	- 0.03	Not Applicable
Δ c-1-3	Tube Inspections; NDE Technique Qualification	Not Applicable	Not Applicable
Δ c-1-4	Tube Inspections; NDE Qualification of Personnel	Not Applicable	Not Applicable
Δ c-2-1	Performance Criteria Commensurate with Adequate Tube Integrity; Model Development	Not Applicable	Not Applicable
Δ c-3-1	Condition Monitoring Assessment; Cost to Perform	Not Applicable	Not Applicable
Δ c-3-2	Condition Monitoring Assessment; Prepare Topical Reports	Not Applicable	Not Applicable
Δ c-3-4	In-situ Pressure Testing	Not Applicable	- 0.05
Δ c-4-1	Operational Assessment; Impact of Operation	Not Applicable	Not Applicable
Δ c-4-2	Operational Assessment; Cost to Perform	Not Applicable	Not Applicable
Δ c-4-3	Operational Assessment; Avoid Unplanned Shutdowns	Not Applicable	+ 0.15
Δ c-4-4	Operational Assessment; Altered Inspection Cycle	Not Applicable	+ 0.10
Δ c-4-5	Operational Assessment; Develop Topical Reports	Not Applicable	Not Applicable
Δ c-4-7	Operational Assessment; Additional Documentation	Not Applicable	Not Applicable
Δ c-5-1	Tube Plugging and Repairs; Prepare ARC Topical Reports	Not Applicable	Not Applicable

Table 3.4 (Continued)

Summary of Reductions in Routine Occupational Health Risk : Industry

ID (see Sec. 3.3 for definition)	DESCRIPTION	Δ ONE TIME Dose, Sv (values are place-holders)	Δ CONTINUOUS Dose, Sv/r-yr (values are place-holders)
Δ c-5-3	Tube Plugging and Repairs; Reduced TS Changes	Not Applicable	Not Applicable
Δ c-5-5	Tube Plugging and Repairs; Changes in Tubes Plugged	+ 0.03	Not Applicable
Δ c-5-6	Tube Plugging and Repairs; Increased Flexibility For SG Tube Replacement	+ 0.06	Not Applicable
Δ c-7-1	Preventive Measures; Prepare Program Topical Reports	Not Applicable	Not Applicable
Δ c--8-1	Primary-to-Secondary Leakage Monitoring/Limits; Hardware/Installation Cost	- 0.03	- 0.03
Δ c-8-3	Primary-to-Secondary Leakage Monitoring/Limits; Maintenance and Training	- 0.01	- 0.02
Δ c-9-1	Radiological Assessment; TS Changes	Not Applicable	Not Applicable
Δ c-10-2	Risk Assessment	Not Applicable	Not Applicable
Δ c--3-1	Report to NRC; Risk for Containment Bypass	Not Applicable	Not Applicable

3.3 Estimation of Impacts

As described previously, this regulatory analysis estimated the values and impacts for the draft SG rule in its entirety, recognizing that the staff concluded that all the draft rule requirements with the exception of the risk related requirements could be imposed on PWR licensees as satisfying the compliance exception criteria of 50.109(a)(4)(i). As such, the costs associated with the "compliance" requirements portion of the draft SG rule would not necessarily be a deciding issue in the staff's decision to pursue imposition of the compliance requirements. However, gaining an understanding of what these costs may be is information that is useful for supporting CRGR review.

This regulatory analysis is based upon 73 PWRs that are assumed located at 49 sites. Essentially identical nuclear steam supply systems (NSSS) were assumed located at the

same site. The different SG designs are treated in the estimation of the impacts as described in Appendix D.

Estimation of impacts is organized and based on the regulatory positions in the draft RG X.XX. We made assumptions with respect to the potential costs or savings to the NRC (I1) and with respect to the potential direct costs or savings to licensees (I2) for each of the programs and procedures developed in Regulatory Positions (Section C) of the draft regulatory guide.

Requirements Comparison Tables were developed to identify and compare the current requirements (listed in the TS and RGs 1.83 and 1.121) and the proposed requirements (listed in RG X.XX). These tables contain an evaluation of the significance of the differences between the current requirements and the proposed requirements.

With this understanding of the differences between the current requirements and the proposed requirements, a list of independent impacts (e.g., primary-to-secondary leakage monitoring hardware cost), imposed on both the industry and the NRC, was developed and binned according to the following program elements found in the RG X.XX:

- C-1 tube inspections provide guidance (1) for assuring, prior to each inservice inspection, degradation mechanisms which may potentially affect the tubing; (2) concerning the development and implementation of NDE data acquisition and analysis procedures for each degradation mechanism; and, pertaining to the frequency of inspection and tube inspection sample size
- C-2 performance criteria that are acceptable to the NRC that address three areas of tube integrity performance: structural integrity; operational leakage; and, accident-induced leakage integrity
- C-3 tube integrity performance based upon a conditional monitoring assessment as "backward looking" in that its purpose is to confirm that adequate tube integrity has been maintained since the previous inspection
- C-4 tube integrity performance based upon an operational assessment as "forward looking" in that it's purpose is to demonstrate reasonable assurance that the tube integrity performance criteria will be met throughout the period prior to the next scheduled tube inspection
- C-5 pertains to plugging and/or repair of defective tubes performed prior to plant restart based upon the results of the tube inspections and operational assessment; provides guidelines for (1) determining the appropriate repair limits for each degradation mechanism; (2) developing appropriate plugging and repair methodologies, including the associated hardware
- C-6 corrective actions to provide reasonable assurance that tube structural and leakage integrity will be maintained prior to the next scheduled inspection and be confirmed as part of the operational assessment program
- C-7 pertains to preventative measures to mitigate active degradation mechanisms and to minimize the potential for new degradation mechanisms; addresses measures for (1) secondary water chemistry control; (2) control loose parts and foreign objects within the

SGs; and, (3) mitigating active degradation mechanisms

- C-8 operational primary-to-secondary leakage monitoring in terms of the development of (1) monitoring programs; (2) allowable limits for operational leakage; and, (3) TS development

- C-9 calculations and methodologies that pertain to radiological doses to (1) demonstrate that the accident leakage performance criterion can be met; and, (2) that TS for the maximum instantaneous dose equivalent ^{131}I, the 48 hour value of dose equivalent ^{131}I, the normal operating primary-to-secondary leakage, and the event induced primary-to-secondary leakage are within a range such that the accident leakage performance criterion is met

- C-10 demonstration that the risk of steam generator thermal failure from severe accident conditions is acceptable, or imposition of corrective actions to reduce the risk to acceptable levels (as a risk-informed regulation, the SG integrity rule recognizes the containment function of SG tubes and consider tube performance under extreme conditions which could result from events normally considered outside the plant design basis, including CD events known as severe accidents)

With the specific "impacts" so specified, the Delta Impact Tables were developed. These tables list the specific impacts that are addressed, and list the pertinent sections of RG X.XX and assign an identification number based on the dominant section of RG X.XX. The tables describe the issues being addressed, and the assumptions and supporting data used in the analysis and summarize the one time and continuing cost impacts on the industry and the NRC. These tables are included as Appendix D.

A summary of the Delta Impact Tables are provided in Sections 3.3.1 and 3.3.2.

3.3.1 Costs Or Savings To NRC (1997 Dollars) (I1)

Table 3.5

Summary Of Cost/Savings: NRC (I1)[1]

ID	DESCRIPTION	Δ ONE TIME COST, $K	Δ CONTINUOUS COST, $K/YEAR
Δ c-3-3	Condition Monitoring Assessment; Review Topical Report	650	50
Δ c-4-6	Operational Assessment; Review Topical Reports	650	50
Δ c-4-8	Review Condition Monitoring and Operational Assessment Reports	NA	585
Δ c-5-2	Tube Plugging and Repairs; Review ARC Topical Reports	1,300	260
Δ c-5-4	Tube Plugging and Repairs; Review of TS Changes	0	NA
Δ c-5-7	Initial TS Amendment Reviews	2,190	NA
Δ c-8-2	Primary-to-Secondary Leakage Monitoring/Limits; NRC Review of TS	1,040	NA
Δ c-9-2	Radiological Assessment; NRC Review of TS Changes	1,040	NA
Δ c-10-1	Risk Assessment	1,095	NA

1. **Each of the elements that make up the NRC Impact is described in Appendix D.**

3.3.2 Direct Costs Or Savings To Licensees (1997 Dollars) (I2)

Table 3.6

Summary Of Cost / Savings : Industry (For a Total of 73 PWRs) (I2) [2]

ID	DESCRIPTION	Δ ONE TIME COST, $K	Δ CONTINUOUS COST, $K/YEAR
Δ c-1-1	Tube Inspections; More Inspection Time	NA	38,900
Δ c-1-2	Tube Inspections; NDE Technique Performance Demonstration Protocol	8,000	NA
Δ c-1-3	Tube Inspections; NDE Technique Qualification	10,800	1,080
Δ c-1-4	Tube Inspections; NDE Qualification of Personnel	NA	1,602
Δ c-2-1	Performance Criteria Commensurate with Adequate Tube Integrity; Model Development	14,600	0
Δ c-3-1	Condition Monitoring Assessment; Cost to Perform	NA	7,300
Δ c-3-2	Condition Monitoring Assessment; Prepare Topical Report	500	50
Δ c-3-4	In-situ Pressure Testing	NA	5,700
Δ c-4-1	Operational Assessment; Impact on Operation	NA	7,081 [3]
Δ c-4-2	Operational Assessment; Cost to Perform	NA	7,300
Δ c-4-3	Operational Assessment; Avoid Unplanned Shutdowns	NA	- 80,000
Δ c-4-4	Operational Assessment; Altered Inspection Cycle	NA	33,600
Δ c-4-5	Operational Assessment; Develop Topical Reports	500	50

Table 3.6 (Continued)

Summary Of Cost / Savings : Industry (73 PWRs) (I2) [2]

ID	DESCRIPTION	Δ ONE TIME COST, $K	Δ CONTINUOUS COST, $K/YEAR
Δ c-4-7	Operational Assessment; Additional Documentation	2,950	7,300
Δ c-5-1	Tube Plugging and Repairs; Prepare ARC Topical Reports	0	0
Δ c-5-3	Tube Plugging and Repairs; TS Changes	13,400	NA
Δ c-5-5	Tube Plugging and Repairs; Change in Tubes Plugged	3,590	NA
Δ c-5-6	Tube Plugging and Repairs; Increased Flexibility For SG Tube Replacement	0	NA
Δ c-7-1	Preventive Measures, Prepare Program Topical Reports	500	NA
Δ c-8-1	Primary to Secondary Leakage Monitoring/ Limits; Hardware Installation Cost	48,000	2,100
Δ c-8-3	Primary to Secondary Leakage Monitoring/ Limits; Maintenance and Training	3,658	1,830
Δ c-9-1	Radiological Assessment; TS Changes	-2,700	NA
Δ c-10-2	Risk Assessment	7,300	NA

2. Each of the elements that make up the Industry Impact is described in Appendix D.
3. This value is the sum of "Costs to Perform Operational Assessment" and "Operational Costs."

3.3.3 Consideration of Rule Variance

An important consideration in evaluating the impacts is the effect of the two rule variants -- performance-based rule and TS-based rule -- on the impacts.

The following table is a repeat listing of the various delta impacts for industry generated for the SG rulemaking activity. The deltas were reviewed and the impact of the 2 rule variants determined: one variant with deltas based solely upon the rule (performance-based); the other variant considers both the rule and regulatory guide (TS-based). The selections were

made principally on judgement as to what impacts might be applicable for each variant. Thus, the entire list of 32 delta impacts correspond to the TS-based rule, where, excluding the 12 shaded deltas, yields the 20 delta impacts for the performance-based rule. The results are shown in the following table.

Table 3.7
Delta Impact from Performance-Based TS-Based Rule

Delta No.	Delta Title	Applicability of Impact
ΔC-1-1	Tube Inspections; More Inspection Time	No change
ΔC-1-2	Tube Inspections; NDE Technique Performance Demonstration Protocol	No change
ΔC-1-3	Tube Inspections; NDE Technique Qualification	No change
ΔC-1-4	Tube Inspections; NDE Qualification of Personnel	No change
ΔC-2-1	Performance Criteria Commensurate with Adequate Tube Integrity; Model Development	No change
ΔC-3-1	Condition Monitoring Assessment; Cost to Perform Assessment	No change
ΔC-3-2	Condition Monitoring Assessment; Prepare Topical Report	No change
ΔC-3-3	Condition Monitoring Assessment; Review Topical Report	Not apply
ΔC-3-4	Condition Monitoring Assessment; In-situ Pressure Testing	No change
ΔC-4-1	Operational Assessment; Impact on Operation	No change
ΔC-4-2	Operational Assessment; Cost to Perform	No change
ΔC-4-3	Operational Assessment; Avoid Unplanned Shutdowns	No change
ΔC-4-4	Operational Assessment; Altered Inspection Cycles	No change
ΔC-4-5	Operational Assessment; Develop Topical Report	No change
ΔC-4-6	Operational Assessment; Review Topical Report	Not apply
ΔC-4-7	Operational Assessment; Additional Documentation	Not apply
DC-4-8	Review Conditional Monitoring and Operational Assessment Report	Not apply
ΔC-5-1	Tube Plugging and Repairs; Prepare ARC Topical Reports	Not apply
ΔC-5-2	Tube Plugging and Repairs; Review ARC Topical Reports	Not apply
ΔC-5-3	Tube Plugging and Repairs; TS Changes	Not apply
ΔC-5-4	Tube Plugging and Repairs; TS Changes (NRC)	No change
ΔC-5-5	Tube Plugging and Repairs; Change in Tubes Plugged	No change
ΔC-5-6	Tube Plugging and Repairs; Increased Flexibility for SG Tube Replacement	No change
ΔC-5-7	Initial Review of TS	Not apply
ΔC-7-1	Preventative Measures; Prepare Program Topical Reports	Not apply
ΔC-8-1	Operational Primary-to-Secondary Leakage Monitoring/Limits; Hardware/Installation Costs	No change
ΔC-8-2	Operational Primary-to-Secondary Leakage Monitoring/Limits; NRC Review of TS	Not apply
ΔC-8-3	Operational Primary-to-Secondary Leakage Monitoring/Limits; Maintenance and Training	No change
ΔC-9-1	Radiological Assessment; TS Changes	Not apply
ΔC-9-2	Radiological Assessment; NRC Review of TS	Not apply
ΔC-10-1	Risk Assessment; (Reserved for Jim Meyer)	No change
ΔC-10-2	Risk Assessment; (Reserved for Jim Meyer)	No change

Note: Shaded deltas that rely upon the draft RG are excluded for the rule alone variant case.

3.4 Evaluation of Values & Impacts

3.4.1 Discussion of Equation for Net Value and/or Impact/Value

Estimated values and impacts are summarized in Table 4.1, namely NV^{B-R}. Values and impacts were combined to form net values "NVs"; the results are reported in Section 4.

The general Net Value equation is as follows:

$$NV = V1+V2+V3+V4+V5 - (I1+I2)$$

A positive value for NV indicates that it is worthwhile, from a value/impact perspective, to proceed with the proposed rule; a negative value indicates that proceeding with the proposed rule would not be cost effective.

3.4.2 Discussion of Approach to Sensitivity and Uncertainty Analysis

Sensitivity studies were performed to assess the effect of different assumptions in the risk (i.e values) and cost (i.e impacts) estimates for the overall draft rule net value assessment. The results of those sensitivity studies are presented in section 4.6.

After review of the draft regulatory analysis results, the staff re-assessed whether a rule was the optimal regulatory approach for addressing the problems with the current regulatory framework. The staff decided that a generic letter approach was a better regulatory approach. As a result, the staff did not expend additional resources to perform an uncertainty analysis for the regulatory analysis on the draft SG rule. Accordingly, section 4.5, which was to present the results of such an uncertainty analysis is left blank.

4. Presentation of Results

The results are presented in a hierarchical decomposition framework, starting with the final results (the net values) and then decomposing the net values into the constituent attributes and finally decomposing the attributes into the important cost and risk results which provide insights into the reasons for the final results.

By way of introduction to the RA results, definitions and assumptions are repeated here for convenience.

<u>Terms Used in Regulatory Analysis</u>

Case	refers to pre- and post- rule implementation status of the plant, i.e., the "base case" as "pre-" and the "rule case" as "post-" rule implementation

Rule Variant	refers to the rule alternatives, currently two; Rule Variant 1 is performance-based while Rule Variant 2 is TS-based
Category	refers to different types of STGR (spontaneous -- Category 1, pressure-induced -- Category 2, severe accident-induced -- Category 3)
Option	refers to the various fixes that are being considered to prevent or mitigate the consequences of the severe accident-induced SGTR. Option 3 has been chosen as the "rule case"; the other options are considered in the sensitivity analysis of Section 4.6

Assumptions Used in Regulatory Analysis

Avoided Risks	the only contribution to reducing risk by implementing the rule is from the Category 3 type of SGTRs, that is, from the severe-accident induced SGTRs. There is no risk reduction, and therefore no value from rule implementation, for the Category 1 & 2 types of SGTRs.
Plants Used	All 73 PWRs were considered in the regulatory analysis. However, for the risk-analysis portion of the RA, that is, for the determination of V1, V2, V3, and V4, the PWRs were broken out into two groups (1) those PWRs that are considered "average"; this group includes all the B&W plants, since the B&W SG/RCS design precludes many of the Category 3 type SGTRs and (2) those PWRs considered "high risk" plants. The risk results for the 10 high risk plants yielded higher core-damage initiating events, higher core damage frequencies, and, most importantly, higher LERFs for the base case.
Variant Use	The two implementation variants (performance-based and TS-based) were only used as a distinguishing feature for the assessment of the Impacts (I1 & I2) and one Value (V5). The other Values (V1, V2, V3 & V4) did not change as a function of the variant. The Net Values presented below are for the two variants.
Release Used	Three radiological release conditions are considered, as described in Section 3, with the first being that associated with the release frequency "RC-1," the LERF. Also considered is the release associated with frequency "RC-2," a lesser release, mitigated by primary and secondary systems, as described in Section 3. For the third condition, the radionuclides released from the core damage accident are contained within the primary, secondary and containment structures.

4.1 Net Values

The Net Value (NV) of the rule implementation is a negative 350 million dollars, assuming a performance-based rule (Rule Variant 1), while it is negative 460 million dollars, assuming

a TS-based rule (Rule Variant 2). Thus, under the assumptions made in this analysis, neither variant of the rule can be justified from a cost-benefit or value-impact point of view.

When examined separately, the net value for the risk related requirements of the draft SG rule (i.e., with the Impacts set equal to zero) is a modest, positive $700,000 per PWR. This net value does not incorporate the actual plant costs associated with actually achieving the assumed risk reduction. These plants costs, in terms of plant modifications, procedure changes, operator training, and supporting analysis are expected to be substantial given the complexity of the severe accident induced SGTR risk issue. It is the staff's judgement that incorporation of these costs into the net value assessment for the risk requirements, and incorporating a less bounding consideration of the potential risk reduction, would result in a net value that is either very small, or more probably negative. As such, the risk requirements could not be supported per 50.109(a)(3) for generic imposition on PWR licensees.

It should be noted that the compliance requirements can be pursued regardless of the results of the overall draft rule net value.

4.2 Attributes

The results for the seven attributes (5 values and 2 Impacts), that together yield the NVs values, are summarized in Table 4.1.

Table 4.1 Net Value Contributions

Attribute	Description	Cost of Impact ($K) Performance-Based	Cost of Impact ($K) TS-Based
V1	Avoided Public Health Risk	28,400	28,400
V2	Avoided Occupational Exposure Risk	600	600
V3	Avoided Offsite Property Damage Risk	11,400	11,400
V4	Avoided Onsite Financial Risk	10,100	10,100
V5	Routine Occupational Exposure	300	200
V	***Total Value***	***50,800***	***50,700***
I1	Cost to NRC	1,100	18,500
I2	Cost to Industry	395,400	491,100
I	***Total Impact***	***396,500***	***509,600***
NV	**Total Net Value**	**-345,700**	**-458,900**

There are a number of important observations that surface from this analysis:

○ The cost to the industry is substantially larger than any other attribute. This cost drives the overall Net Value results, that is, the large negative Net Value. The key contributors to this high industry cost are the continuous costs from altered inspection cycles, the continuous costs of increased tube inspections, and the one-time costs associated with primary-to-secondary leakage monitoring hardware installation.

○ The cost to the industry is less by approximately $95 million if the performance-based rule is adopted as compared to the more prescriptive TS-based rule.

○ If all the Impacts were zero, the Net Value would be a positive value of $51 M or only about $700,000 per PWR -- a relatively small amount for justifying procedural and, much less, hardware backfits.

○ The avoided risks (V1 through V4) were calculated assuming 10 "high risk" PWRs. Although they represent only 14% of the PWRs, they contribute to two thirds of the avoided risk.

4.3 Important Risk Results

Severe Accident Consequences Resulting from Induced Steam Generator Tube Rupture

The staff performed an integral analysis of the offsite consequences of 100 gpm and 500 gpm SG tube leaks and a single tube induced steam generator tube rupture (ISGTR). The incremental dose contribution from the 3 and 5 tube ISGTRs was also determined. For this assessment, source terms obtained from MELCOR analyses of station blackout (SBO) sequences were used with 100 gpm and 500 gpm SG tube leaks and an ISGTR at the Surry site. The resulting source terms were used as input to the MELCOR Accident Code Consequence System (MACCS) analysis. The Surry site and meteorological data files, as used in NUREG-1150, were used for this analysis. The offsite consequences were calculated out to 50 miles consistent with guidance in NUREG/BR-0058, Rev. 2, Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission.

The results of the MELCOR Accident Code Consequences System (MACCS) are shown below. The MACCS calculations used the Surry site parameters and the protective actions assumed in NUREG-1150 (a general site emergency is declared after 4 hours and after a 2-hour delay 99.5% of the people within 10 miles evacuate to 20 miles).

	1 Tube ISGTR	3 Tube ISGTR	5 Tube ISGTR
Early Fatalities	3.96E-05	0.352	1.25
Latent Cancer Fatalities	389	1,110	1,330
Population Dose, person-Sv (person rem)	1.13E+04 (1.13E+06)	3.69E+04 (3.69E+06)	4.42E+04 (4.42E+06)

The details of this analysis are described in NUREG-1570, "Risk Assessment of Severe Accident Induced Steam Generator Tube Rupture." From this analysis, the conditional consequences (conditional on a SGTR, containment bypass event occurring, that is, conditional on a large early release from the Surry PWR at the Surry site) ranged from 1E+04 person-Sv to 4E+4 person-Sv. The conditional consequence value chosen for the regulatory analysis for the Surry reactor at the Surry site was 2E+4 person-Sv calculated out to 50 miles. The analysis methodology is described in Section 3.

Risk Results for the Base Case and the Rule Cases

Following the methodology described in Section 3, the following risk results are summarized. The important risk measures are the CDFs and the corresponding LERFs. The risk results are summarized in Table 4.2.

Table 4.2 Summary of Risk Results

Core Damage Frequencies (per reactor year)

Item	Base Case	Rule Case (Performance-Based)	Rule Case (TS-Based)
Spontaneous SGTR (Category 1)	1.0E-6	not analyzed[1]	not analyzed[1]
Pressure Induced SGTR (Category 2)	3.0E-6	not analyzed	not analyzed
Temperature Induced SGTR (Category 3)			
Representative PWR (63 PWRs)	1.6E-5	1.6E-5	1.6E-5
High Risk PWR (10 PWRs)	1.0E-4	1.0E-4	1.0E-4
Average PWR (73 PWRs)	2.8E-5	2.8E-5	2.8E-5
SGTR Total	3.2E-5	3.2E-5	3.2E-5

Large-Early Release (RC-1) Frequencies (LERFs) (per reactor year)

Item	Base Case	Rule Case (Performance-Based)	Rule Case (TS-Based)
Spontaneous SGTR (Category 1)	1.0E-6	not analyzed[1]	not analyzed[1]
Pressure Induced SGTR (Category 2)	3.0E-6	not analyzed	not analyzed
Temperature Induced SGTR (Category 3)			
Representative PWR (63 PWRs)	3.2E-6	2.8E-7	2.8E-7
High Risk PWR (10 PWRs)	4.5E-5	3.4E-6	3.4E-6
Average PWR (73 PWRs)	8.9E-6	7.1E-7	7.1E-7
SGTR Total	1.3E-5	4.7E-6	4.7E-6

Attenuated Release (RC-2) Frequencies (per reactor year)

Item	Base Case	Rule Case (Performance-Based)	Rule Case (TS-Based)
Spontaneous SGTR (Category 1)	0.0	not analyzed[1]	not analyzed[1]
Pressure Induced SGTR (Category 2)	0.0	not analyzed	not analyzed
Temperature Induced SGTR (Category 3)			
Representative PWR (63 PWRs)	2.6E-7	0.0	0.0
High Risk PWR (10 PWRs)	5.1E-6	0.0	0.0
Average PWR (73 PWRs)	9.2E-7	0.0	0.0
SGTR Total	9.2E-7	0.0	0.0

Footnote 1 "not analyzed" -- since there is no risk reduction for these cases, no "Rule Case" analysis was performed. The values are the same as for the "Base Case."

Spontaneous SGTR (Category 1)

The CDF for the Base Case is 1E-6/r-yr while the corresponding large release (RC1) is also 1E-6/r-yr. The CDF of 1E-6/r-yr was chosen as representative of the PRA results to date for core damage events that result from spontaneous SGTRs (as initiators). It was further assumed that all SGTR core damage events result in direct releases into the environment, that is, they bypass the containment and result (with a conditional probability of 1.0) in a stuck open secondary safety or dump valve. Assuming that the CDF of 1E-6/r-yr is correct, this is a worst-case scenario. All of the CDF is assigned to RC-1 or LERF.

Since it is assumed that there is no reduction in risk from spontaneous SGTR (Category 1) by implementing the rule, the rule cases were not analyzed; both rule variants are the same as the base case. The report NUREG-1570 describes how these values were determined.

Pressure Induced SGTR (Category 2)

The core damage frequency (CDF) for the Base Case is 3E-6/r-yr while the corresponding large release (RC1) is also 3E-6/r-yr. The CDF of 3E-6/r-yr was chosen as representative of the PRA results to date for core damage events that result from pressure induced SGTRs (as initiators). It was further assumed that all SGTR core damage events result in direct releases into the environment, that is, they bypass the containment and result (with a conditional probability of 1.0) in a stuck open secondary safety or dump valve. Assuming that the CDF of 3E-6/r-yr is correct, this is a worst-case scenario. All of the CDF is assigned to RC-1 or LERF.

Since it is assumed that there is no reduction in risk from pressure induced SGTR (Category 2) by implementing the rule, the rule cases were not analyzed; both rule variants are the same as the base case. NUREG-1570 describes how these values were determined.

Temperature Induced (Otherwise Referred to as Severe Accident-Induced) SGTR (Category 3)

As described in Section 3, the risk which results from temperature induced SGTR is reduced by rule implementation. For this category of SGTRs, the PWRs were divided into two groups: representative PWRs and high risk PWRs. Of the total of 73 PWRs, 10 were determined to be in the high risk category. The base case CDFs are 1.6E-5 for the representative PWRs and 1.0E-4 for the high risk PWRs, yielding a weighted average CDF of 2.8E-5 for all PWRs. All these CDFs are for core damage events that set the stage for temperature induced SGTRs, that is, events that have a medium to high primary system pressure and a dry secondary. Section 3 describes the accident progression event tree used to analyze the progression from core damage to release to the environment. The base case

LERFs are 3.2E-6 for the representative PWRs (20% of the CDF) and 4.5E-5 for the high risk PWRs (45% of the CDF), yielding a weighted average CDF of 8.9E-6 for all PWRs (29% of the CDF).

The rule case CDFs are 1.6E-5 for the representative PWRs and 1.0E-4 for th high risk PWRs, yielding a weighted average CDF of 2.8E-5 for all PWRs -- the same as the corresponding values for the base case. They are the same since all the risk reduction from rule implementation is assumed to come from mitigating the consequences of the core damage events with initially high primary system pressure and dry secondaries, not from preventing these core damage events. The rule case LERFs are 2.8E-7 for the representative PWRs (2% of the CDF) and 3.4E-6 for the high risk PWRs (3% of the CDF), yielding a weighted average CDF of 7.1E-7 for all PWRs (3% of the CDF).

Risk Reduction Results -- The Avoided Risks

The risk reduction results for the temperature induced SGTRs are summarized in Table 4.3.

Table 4.3 Summary of Risk Reduction Results

Item	Rule Case to Base Case (both rule variants yield identical results)
Change in CDF: *All PWRs* (per reactor-year)	0.0
Change in LERF: *Representative PWRs* (RC-1) (per reactor-year)	2.9 E-6
Change in LERF: *High Risk PWRs* (RC-1) (per reactor-year)	4.2 E-5
Change in LERF: *Average PWR* (RC-1) (per reactor-year)	8.2 E-6

The avoided risk results from a combination of hardware and procedural backfits that prevent the depressurization of the secondary side of the SGs. These backfits prevent temperature induced SGTR by lowering the probability of early SG depressurization and by reducing to zero the probability of late SG depressurization. The event tree input that yielded the avoided risk values is listed in Table 3.1 of Section 3. The results of considering other options, also listed in Table 3.1, are described in Section 4.6, "Results of Sensitivity Analysis."

4.4 Discussion of Non-Quantified Issues

Based on a cursory review of IPE data, some PWRs have a greater potential for core damage events which could result in thermal challenges to SG tubes. Since IPE submittals did not address in detail the effect of tube degradation on SG tube integrity under severe accident conditions, the potential for those PWRs with a higher potential for such core damage events to have a correspondingly elevated LERF potential via thermally induced SGTRs would need to be assessed on a plant specific basis. The level of risk for a specific plant is a function of its plant specific features including its susceptibility to certain categories of core damage events, the thermal-hydraulic response of the plant during such events, and the condition of its SG tubes.

4.5 Results of Uncertainty Analysis

After review of the draft regulatory analysis results, the staff re-assessed whether a rule was the optimal regulatory approach for addressing the problems with the current regulatory framework. The staff decided that a generic letter approach was a better regulatory approach. As a result, the staff did not expend additional resources to perform an uncertainty analysis for the regulatory analysis on the draft SG rule. Accordingly, this section is left biank.

4.6 Results of Sensitivity Analysis

4.6.1 Sensitivity to Variations in Severe Accident Progression

The sensitivity analysis considers the seven options (some of which are backfits) that are listed in Table 3.2 of Section 3. Figure 4-1 presents a bar-graph summary of the risks avoided for the seven options. Note that the greatest benefit, in terms of risk avoided, is Option 3 -- the option selected as the rule case. Below is a discussion of the results for each of the options.

Option 1 No Late SG Depressurization

This Rule sensitivity option presumes that MSIV leakage can be entirely prevented. The split fraction, therefore, for "No Late Secondary Depressurization" becomes zero.

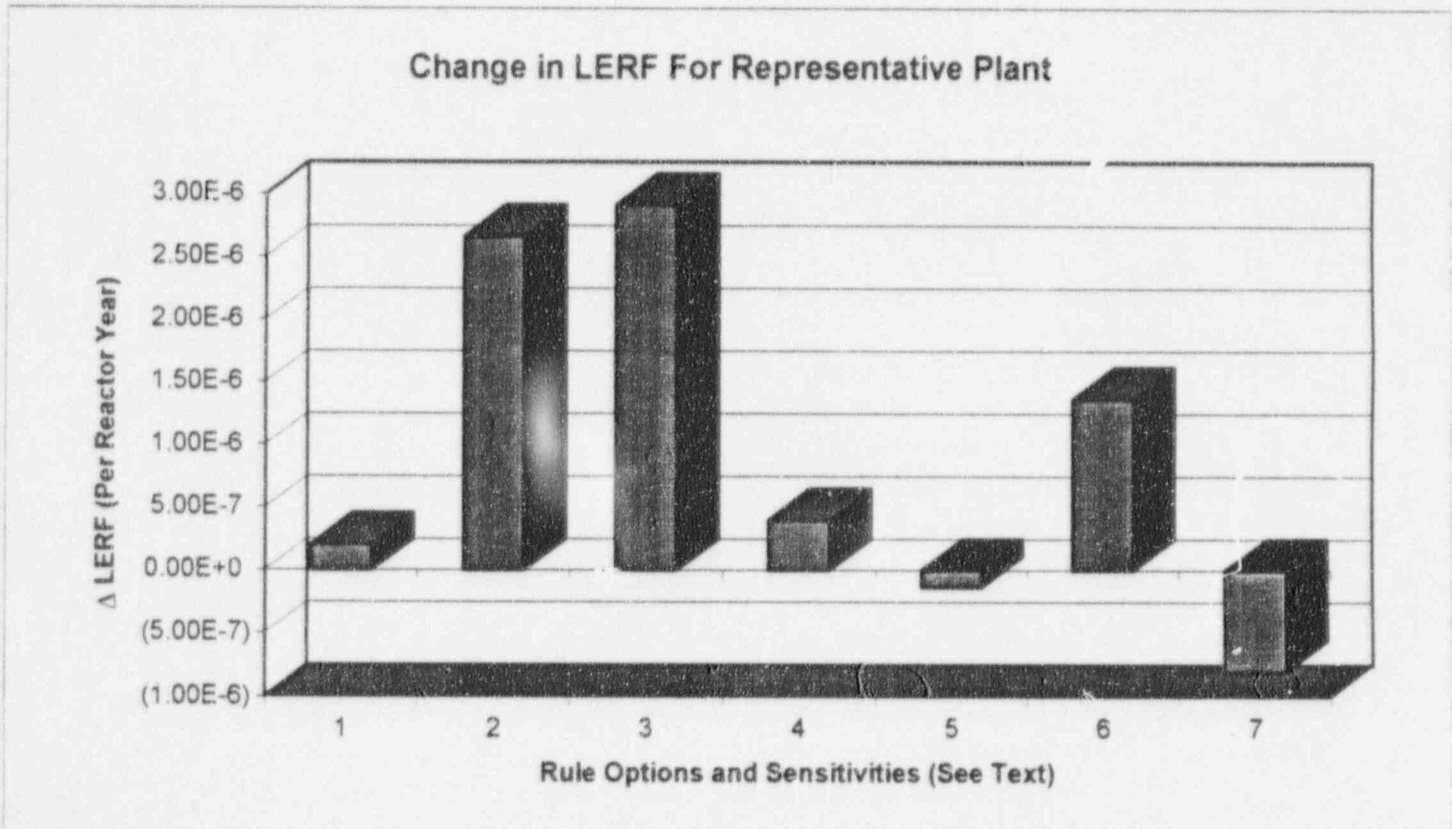


Figure 4-1 Change in LERF for Representative Plant

Option 2 Lower Early SG Depressurization

Secondary depressurization immediately following core uncovery is divided into two top events; [D]: Operator Control of Secondary Pressure, and [E]: No Stuck Open Relief Valve in Secondary. The raw data used to develop the split fractions for these events are shown in the following table.

	Reference	Option #2
Operator Control of Secondary Pressure	38%	3%
No Stuck Open Relief Valve in Secondary	36%	2%

The resulting chance of early secondary depressurization reduces by a factor of 15.

Option 3 Option 1 and 2

This Rule sensitivity option combines options 1 and 2.

Option 4 Perfect Late Primary Depressurization

The 50% probability of late primary depressurization is changed to 100%, reflecting a perfect ability tc reduce primary pressure late in the accident.

Option 5 No Late Primary Depressurization

The 50% probability of late primary depressurization is changed to 0%, reflecting inability to reduce primary pressure.

Option 6 No RCP Seal LOCA

In the event trees the probability of a Seal LOCA is not explicit, due to its dependence on the previous top event. Its effective probability is 18%, equivalent to a split fraction of 21%. This option assumes that a Seal LOCA is perfectly preventable, reducing this number to 0%.

Option 7 Increase in SG tube temperature from best-estimate by 70°K

The model used to generate flaw distributions for TI-SGTR analysis was adjusted for higher temperatures. The split fractions for the top event (I: No TI-SGTR) increased accordingly.

4.6.2 Sensitivity Study - Voluntary Actions

As has been noted in this report, the estimation of impacts (costs) of the draft SG rule framework versus the current regulatory framework was based on a comparison of the requirements before and after rule implementation. Voluntary actions were not accounted for in the analysis; this is consist with regulatory analysis guidelines. The staff recognizes that the industry, on a voluntary basis, has implemented a significant number of SG tube inspection actions. These actions stem from a significant investment by the industry, through EPRI, to develop and implement improved inservice inspection guidelines, that incorporate tube inspection guidelines, updated knowledge on corrosion mechanisms, operating experience, degradation-specific management experience, and performance standards. In many cases, licensees have implemented the improved ISI guidelines without encouragement from the NRC. In other cases, when a licensee experiences significant SG degradation, NRC interaction has caused licensees to significantly enhance their SG tube surveillance and maintenance activities. In fact, some licensees have begun to implement portions of the draft SG RG. Although these measures do not fully satisfy the draft SG RG, they represent a significant enhancement beyond the minimum TS requirements. Recognizing this situation, a sensitivity study was performed that estimates the additional costs that industry would incur due to imposition of the draft rule requirements given credit to the voluntary actions that licensees already implement. This sensitivity gives a more accurate picture of the cost impact of implementing the draft SG rule or equivalent regulatory approach (i.e. any approach where the staff wants to impose the additional requirements to inspect, assess, and monitor the condition of the SG tubes consistent with the draft SG RG guidance). The associated reduced impacts (I1 and I2) that account for licensee voluntary actions are given in the following data tables (Table 4.4 and Table 4.5)

The results of this sensitivity analysis are shown in Table 4.6. The Net Value for this "Voluntary Actions" sensitivity study is minus $100M. Although this number is less-negative than the reference NV number ($460M), it continues to support the conclusion that the regulatory analysis does not support rulemaking.

Note that the (TS-Based) Industry-Impact value drops considerably when considering the Voluntary Actions Case (from $491M to $143M), thus showing that, according to this analysis, the industry has already invested about $491M - $143M or $348M in SG-related improvements.

Table 4.4
Summary Of Cost/Savings: NRC (I1)[1]
(Sensitivity Studies - Voluntary Actions)

ID	DESCRIPTION	Δ ONE TIME COST, $K	Δ CONTINUOUS COST, $K/YEAR
Δ c-3-3	Condition Monitoring Assessment; Review Topical Report	650	50
Δ c-4-6	Operational Assessment; Review Topical Reports	650	50
Δ c-4-8	Review Condition Monitoring and Operational Assessment Reports	NA	0
Δ c-5-2	Tube Plugging and Repairs; Review ARC Topical Reports	0	0
Δ c-5-4	Tube Plugging and Repairs; Review of TS Changes	0	NA
Δ c-5-7	Initial TS Amendment Reviews	2,190	NA
Δ c-8-2	Primary to Secondary Leakage Monitoring/Limits; NRC Review of TS	1,040	NA
Δ c-9-2	Radiological Assessment; NRC Review of TS Changes	1,040	NA
Δ c-10-1	Risk Assessment	1,095	NA

1. Each of the elements that make up the NRC Impact is described in Appendix D.

Table 4.5
Summary Of Cost / Savings : Industry (For a Total of 73 PWRs) (I2) [2]
(Sensitivity Studies - Voluntary Actions)

ID	DESCRIPTION	Δ ONE TIME COST, $K	Δ CONTINUOUS COST, $K/YEAR
Δ c-1-1	Tube Inspections; More Inspection Time	NA	0
Δ c-1-2	Tube Inspections; NDE Technique Performance Demonstration Protocol	1,600	NA
Δ c-1-3	Tube Inspections; NDE Technique Qualification	10,800	236
Δ c-1-4	Tube Inspections; NDE Qualification of Personnel	NA	320
Δ c-2-1	Performance Criteria Commensurate with Adequate Tube Integrity; Model Development	14,600	0
Δ c-3-1	Condition Monitoring Assessment; Cost to Perform	NA	7,300
Δ c-3-2	Condition Monitoring Assessment; Prepare Topical Report	500	50
Δ c-3-4	In-situ Pressure Testing	NA	5,700
Δ c-4-1	Operational Assessment; Impact on Operation	NA	2,360 [3]
Δ c-4-2	Operational Assessment; Cost to Perform	NA	5,500
Δ c-4-3	Operational Assessment; Avoid Unplanned Shutdowns	NA	- 26,800
Δ c-4-4	Operational Assessment; Altered Inspection Cycle	NA	0
Δ c-4-5	Operational Assessment; Develop Topical Reports	500	50
Δ c-4-7	Operational Assessment; Additional Documentation	2,950	7,300
Δ c-5-1	Tube Plugging and Repairs; Prepare ARC Topical Reports	0	0
Δ c-5-3	Tube Plugging and Repairs; Reduced TS Changes	13,400	NA

Table 4.5 (Continued)
Summary Of Cost / Savings : Industry (73 PWRs) (I2) [2]
(Sensitivity Studies - Voluntary Actions)

ID	DESCRIPTION	Δ ONE TIME COST, $K	Δ CONTINUOUS COST, $K/YEAR
Δ c-5-5	Tube Plugging and Repairs; Change in Tubes Plugged	482	NA
Δ c-5-6	Tube Plugging and Repairs; Increased Flexibility For SG Tube Replacement	0	NA
Δ c-7-1	Preventive Measures, Prepare Program Topical Reports	500	NA
Δ c-8-1	Primary-to-Secondary Leakage Monitoring / Limits; Hardware Installation Cost	23,500	2,100
Δ c-8-3	Primary-to-Secondary Leakage Monitoring/ Limits; Maintenance and Training	3,658	1,830
Δ c-9-1	Radiological Assessment; TS Changes	-2,700	NA
Δ c-10-2	Risk Assessment	7,300	NA

2. Each of the elements that make up the Industry Impact is described in Appendix D.
3. This value is the sum of "Costs to Perform Operational Assessment" and "Operational Costs."

Table 4.6
Summary Of Cost / Savings : Industry (73 PWRs) (I2) [2]
(Sensitivity Studies - Voluntary Actions)

Attribute	Description	Cost of Impact ($K) TS-Based
V1	Avoided Public Health Risk	28,400
V2	Avoided Occupational Exposure Risk	600
V3	Avoided Offsite Property Damage Risk	11,400
V4	Avoided Onsite Financial Risk	10,100
V5	Routine Occupational Exposure	200
V	***Total Value***	***50,700***
I1	Cost to NRC	7,800
I2	Cost to Industry	143,600
I	***Total Impact***	***151,400***
NV	**Total Net Value**	**-100,700**

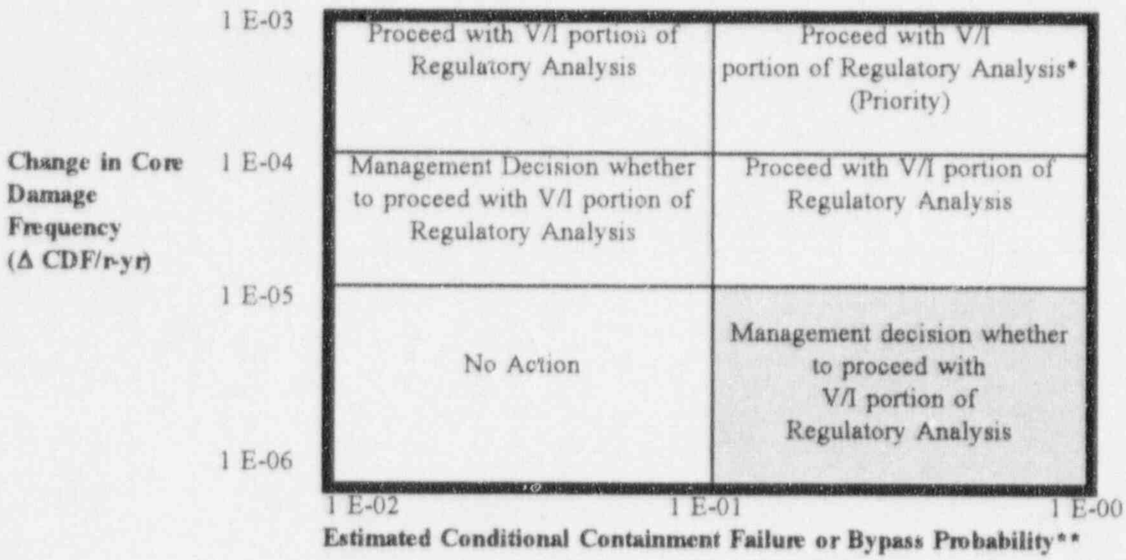
4.7 Safety Goal Evaluation

This proposed regulatory action is subject to a safety goal evaluation. A satisfactory finding relative to the proposed safety goal screening criteria is considered a prerequisite for achieving the substantial additional protection criteria of the backfit standard in 10 CFR 50.109 (a) (3). Proposed actions subject to the backfit rule [except for backfits falling within the three exception categories of 10 CFR 50.109(a)(4)], are required by 10 CFR 50.109(a)(3) to show that there is a substantial increase in the overall protection of public health and safety and that the costs of implementation are justified in view of this increased protection. A clearly positive finding with respect to the net value or value-impact ratio would normally satisfy this standard.

Normally, guidance on how to proceed with the value-impact portion of the regulatory analysis is provided by using Figure 4-2, Safety Goal Decision Criteria. However for this RA, there is no anticipated "change in core damage frequency (CDF)" due to rule implementation. The CDF does not change; rather the LERF changes from anticipated fixes that mitigate the consequences of the severe accidents considered (Δ LERF of the analysis - 8×10^{-6}/r-yr). Thus, none of the six blocks in the figure apply, even though the estimated conditional containment failure or bypass probability is essentially 100%. For this SGTR action, however, the spirit of this safety goal decision criteria is that it should be a "management decision whether to proceed with the V/I portion of the

Regulatory Analysis." Based, in part, on this, the staff proceeded with the V/I (Net Value) portion of the regulatory analysis.

Figure 4-2 Safety Goal Decision Criteria



* A determination is needed regarding adequate protection or compliance; as a result, a value/impact analysis may not be appropriate.

** Conditional upon core damage accident that releases radionuclides into the containment or into the secondary side systems via SGTR.

5. Decision Rationale for Selection of the Proposed Action

The regulatory analysis documented in this report was conducted to determine if the benefits to public health and safety associated with implementing the requirements and guidance in the draft rule and draft regulatory guide met the 10 CFR 50.109 criteria for a generic backfit. The staff and its contractor estimated values (i.e., averted public risk, averted occupational exposure risk, averted offsite and onsite property damage risk) and impacts (i.e., costs to industry and costs to NRC) and assessed their net value, associated with generic imposition of the proposed requirements. Also, the staff developed justifications to support invoking the exception criteria of 10 CFR 50.109(a)(4) for the requirements that the staff concluded are necessary in order to maintain compliance with existing regulations and licensing bases. Finally, based on the results of the sensitivity studies and the IPE examinations, the staff considered the potential for plant specific actions. The staff drew the following major conclusions from this work:

1. Necessary revisions to requirements for inspecting, monitoring and assessing the condition of the SG tubes, and for maintaining SG tube integrity can be implemented

as compliance backfits. Specifically, changes from what currently exists in plant TS can be justified to ensure that SG tube surveillance and maintenance are accomplished consistent with 10 CFR Part 50, Appendix B; 10 CFR 50.55a; guidance in 10 CFR Part 50 Appendix A; and plant licensing bases. These revisions are currently being addressed on an ad hoc basis.

2. Additional requirements for licensees to take actions in order to reduce risk cannot be justified on a generic basis as satisfying the 10 CFR 50.109(a)(4) backfit criteria. Using the applicable values and impacts, the staff concluded that additional requirements could not be justified for all pressurized-water reactor (PWR) licensees on a cost-justified basis in accordance with 10 CFR 50.109(a)(3). The staff analysis did not eliminate the possibility that plant-specific backfits might be appropriate for plants that pose SGTR-related risks well above those demonstrated in the example plant analysis. For a plant to pose a substantially higher risk, it would need to have a combination of a) high frequency for core damage sequences with moderate-to-high RCS pressures and dry SGs, b) unfavorable level of tube degradation, c) thermal-hydraulic characteristics that result in high SG tube temperatures and differential pressures, d) unfavorable site characteristics and e) sufficient remaining plant life to offer high averted risk. Information is available for some of the plant characteristics listed above (e.g., event frequency and site parameters). This will help identify plants for which additional assessments may be appropriate to determine if they pose sufficient risk from severe accident-induced SGTRs to warrant backfit consideration.

Given the major conclusions discussed above, the staff has reassessed whether a rule is the appropriate regulatory vehicle for addressing the problems associated with SG tube integrity. The regulatory analysis does not support mandating on a generic basis additional requirements on PWR licensees to take actions to reduce risk. However, it was also concluded that additional requirements for inspecting, monitoring and assessing SG tube condition, and maintaining SG tube integrity for the planned operating cycle are necessary and should be pursued as compliance backfits to existing regulations in accordance with 10 CFR 50.109(a)(4)(i). Since no new generic requirements regarding risk reduction are to be required and the only generic action is to require changes in SG tube surveillance and maintenance to satisfy the existing regulations and design bases, the staff has concluded that promulgation of a new rule is not necessary.

The staff's risk assessment did indicate the potential that relaxations of the repair criteria currently in PWR TS could result in increased risk. The exact change in risk cannot be evaluated until the specifics of the proposed change in SG repair criteria are presented. Therefore, the staff has concluded that proposed license amendments to change SG tube repair criteria beyond those approaches and criteria previously approved, should be supported by an appropriate risk assessment that will require staff review and approval prior to implementation of the alternate repair criteria.

Based on the above, the staff plans to pursue the following approach in lieu of SG rulemaking:

1. Complete development of a SG tube integrity regulatory guide which describes an acceptable performance-based program for ensuring adequate tube inspection, monitoring, and assessment.

2. Request licensees, through a generic letter, to propose performance-based TS changes to address the issues regarding inspection, monitoring, and assessment of SG tube condition to ensure that SG tube integrity is maintained consistent with the plant licensing basis. The SG tube integrity RG would provide guidance to licensees on an acceptable approach and program for addressing these issues.

3. Provide licensees with an option to change current SG tube repair criteria and implement a degradation-specific management approach, if it can be demonstrated that risk will be maintained at an acceptable level. Draft regulatory guide DG-1061, in conjunction with an application-specific regulatory guide would provide guidance on acceptable approaches for proposing changes to SG tube integrity criteria and assessing changes in risk associated with relaxation of tube integrity criteria. Licensees would not be able to implement alternate repair criteria until an appropriate risk assessment is submitted and found acceptable by the staff. This approach is consistent with the staff's current approach for addressing risk-informed ISI, IST, graded QA, and TS.

4. As part of the IPE follow-up program, the staff will evaluate PWRs which appear to have the potential for substantial safety improvements in the area of SG tube integrity. Any additional requirements would be imposed consistent with the backfit requirements of 10 CFR 50.109."

[*As discussed above, the results of the regulatory analysis of the draft SG rule caused the staff to re-evaluate the regulatory approach for resolving the difficulties associated with the current regulatory framework governing SG tube integrity. As a result of the staff decision to utilize a generic letter approach in lieu of a new rule, additional resources were not expended to complete sections 5.1 through 5.6.*]

5.1 The Relative Importance of Non Quantifiable Attributes

5.2 The Relationship and Consistency of the Proposed Alternatives with the NRC's Legislative Mandates, Safety Goals, and Policy and Planning Guidance that are in Effect at the Time the Proposed Alternative is Recommended

5.3 The Impact of the Proposed Action on Existing or Planned NRC Programs and Requirements

5.4 A Statement of the Proposed Generic Requirement or Staff Position as is Proposed to be Sent Out to Licensees

5.5 A Statement of the Sponsoring Office's Position as to Whether the Proposed Action Would Increase or Relax (or Reduce) Existing Requirements or Staff Positions

5.6 A Statement on Whether the Proposed Action is Interim or Final, and If Interim, the Justification for Imposing the Proposed Backfit on an Interim Basis

6. Implementation

The regulatory analysis sets forth the regulatory framework for the proposed rulemaking action. Implementation action is stated in subpart (c) (1) and (2) of the proposed rule.

7. Rule Impact

This aspect is fully discussed in Section 3 and 4 of the analysis.

8. Proposed Rule: Final or Interim

The staff has proposed the following version of a draft performance-based SG rule.

DRAFT
Steam Generator Rule
November 5, 1996

50.xx Steam Generator Tube Integrity

(a) Applicability
The requirements of this section apply to all applicants for and holders of construction permits and operating licenses for commercial pressurized water nuclear power plants.

(b) Requirements.
(1) Each licensee subject to the requirements of this section shall monitor and maintain the condition of the steam generator tubes consistent with the performance criteria in paragraph (b)(3) to provide reasonable assurance that the steam generator tubes remain capable of fulfilling their intended safety functions. The steam generator tubes are relied upon to function as part of the reactor coolant pressure boundary, to isolate radioactive fission products in the primary coolant from the secondary system and the environment, to function as a heat transfer surface for removing residual heat to ensure the capability to shut down the reactor and maintain it in safe shutdown condition, and to prevent or mitigate the consequences of design basis accidents. In addition, the tubes are relied upon to maintain their integrity consistent with containment objectives of preventing uncontrolled fission product release under conditions resulting from core damage severe accidents.

(2) The licensee shall notify the Commission within 24 hours and shall take appropriate corrective action if the condition of the steam generator tubes does not meet performance criteria in paragraph (b)(3).

(3) To provide reasonable assurance that the tubes remain capable of performing their intended safety functions, NRC approved performance criteria shall be established which are commensurate with adequate tube integrity under the conditions of normal operation, including anticipated operational occurrences, design basis accidents, external events, and natural phenomena for which the tubing must perform the functions identified in paragraph (b)(1). These performance criteria shall include criteria for the tube structural integrity, operational leakage integrity, and accident-induced leakage integrity and shall be established consistent with the following:

(i) Structural Integrity Criteria: All tubes shall retain margins of safety against rupture consistent with the stress limits of the ASME Boiler and Pressure Vessel Code, Section III, 1989 edition. Alternatively, the probability of tube ruptures as initiating or consequential events shall be limited such as to ensure compliance with 10 CFR 50, Appendix A, General Design Criteria 14 and 31, and low risk.

(ii) Operational Leakage Criteria: Operational primary-to-secondary leakage in each steam generator should not exceed a value consistent with providing reasonable assurance against abnormal leakage or gross rupture of the tubing.

(iii) Accident Induced Leakage Criteria: The potential primary-to- secondary leakage rate associated with the most limiting postulated accident shall not exceed the total charging pump capacity of the primary system and shall be such that the associated offsite dose consequences are in accordance with 10 CFR Part 100 Guidelines or some small fraction of Part 100 guidelines, as appropriate to the accident, and the associated radiological consequences to control room personnel are in accordance with 10 CFR 50, Appendix A, General Design Criteria 19.

(4) To ensure the performance criteria are met, each licensee shall:

(i) Manage the types, extent, and severity of degradation that may affect steam generator tubing through a combination of:

(a) preventive measures, as practical, to minimize the potential for tube degradation and to mitigate active mechanisms,

(b) inservice inspection of the tubing with respect to acceptance criteria for degraded tubing,

(c) plugging and/or repair of tubing which fail to meet the acceptance criteria,

(d) monitoring of operational primary-to-secondary leakage and implementing leakage limits such that the applicable performance criteria are not exceeded,

(e) monitoring of the "as-found" condition of the tubing during each inservice inspection with respect to the applicable tube performance criteria (i.e., condition monitoring), and

(f) monitoring of the projected condition of the tubing calculated to exist during future operation with respect to the applicable tube performance criteria (i.e., operational performance).

such that there is reasonable assurance that the performance criteria are not exceeded.

(ii) Utilize inservice inspection systems (i.e., techniques, procedures, and personnel) which have been demonstrated to be reliable for all flaw mechanisms affecting the tubing such that plugging or repairs may be implemented before the performance criteria are exceeded.

(iii) Utilize inspection and/or test methods and analysis methods for condition monitoring such as to provide high confidence in the assessment of the condition of the tubing relative to the performance criteria.

(iv) Utilize analysis methods for operational assessment such as to provide high confidence in the evaluation of the projected condition of the tubing relative to the performance criteria.

(5) Licenses shall maintain measures for mitigating the consequences of occurrence involving abnormal leakage or gross rupture of the tubing.

(6) Licensees shall take reasonably achievable measure necessary to preserve the steam generator tube function as a barrier against the uncontrolled release of fission products.

(c) *Implementation*

(1) Each licensee subject to the requirements of this section shall submit a request for revision to the technical specifications to implement the provisions of this section no later than [DATE]. The submittal for technical specification revision must contain justification, including supporting analyses and data, if the licensee chooses to deviate from guidance either approved or endorsed by the Commission.

(2) The requirements of this section supersede the requirements of 50.65 as it applies to the maintenance of the steam generator tubes.

The accompanying draft Regulatory Guide X.XX, Steam Generator Tube Integrity, was issued on November 5, 1996 and is attached as Appendix E to this Regulatory Analysis.

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APPENDIX A: Discussion of Improvements in Steam Generator Performance Due To Rule Implementation

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Appendix A

Although this analysis does not assign any quantitative risk reduction for rule implementation as it is affected by spontaneous SGTRs, there are qualitative arguments for improvement. These arguments, broken out by elements of the regulatory guide, are described in this appendix.

Effect of Inspection

The effect of inspection on the reduction of SGTR is a function of the improvement and refinement in knowledge about the flaw state of the SG tubes. The control on the improvement of performance of inspection is derived from the performance demonstration, which calls for qualification of techniques and personnel on real flaws in a statistically significant manner. One incentive of the RG is that the control of the performance demonstration is not restrictive and thereby allows for the development of new and improved approaches in inspection. Another incentive of the RG is that the results of the inspection are used for analytical approaches (deterministic and probabilistic) of the performance criteria for the SG tubing. This incentive provides an increased conservatism in the measurement of the flaw state which is balanced with a decreased margin from more exact analytical resolutions of the flaw state impact on performance.

A key variable in the improvement of industry performance is the effect of the enhancements in the measurement of flaw state. This refinement of the measurement of flaws is composed of three parts. Each of these areas will be treated separately with regard to their effect on the reduction of the probability of SG tube rupture leaks.

- One potential improvement under the new rule is an enhancement of the detectability of any flaw. This would be captured in the probability of detection (POD) for each mode of damage.

  This analysis assumes, based on industry experience, that detectability problems are always solvable by experimentation using real flaws. This occurs through the improvements in existing technology, or changes to alternate inspection technologies when the existing technology is inadequate. The industry experience in this regard has been reactive, and the failures of examination technology in the field have led in every case to improvements in inspection approaches.

  This analysis assumes that the performance demonstration will result in a proactive culling of technologies so that appropriate examination techniques are quantified for discriminating between specific modes of tube damage. It was also assumed that a consequence of the new rule will be an enhancement in the probability of the detection of flaws and a decrease in the uncertainty of the frequency distribution of detected indications and enhancements in the distribution of rates for new indications. More reliable detection of flaws will increase the population of detection, enhance the operational assessments, and increase the probability of the removal of these flawed

tubes prior to failure. Better defined flaw states will be needed to support the operational assessment for SG tubing.

The quantification of the effect of enhanced detection requires a modeling effort with details beyond the scope of this discussion. However, extreme assumptions can be made to see the general effect of improvement in the probability of detection on decreasing the probability of SGTR. For instance, this analysis projects a case of a crack-like flaw which is relatively difficult to detect and the critical depth for rupture of 60% is assumed. It is further assumed that the current NDE capabilities are limited to allow detection at 40% through-wall and greater and that the crack is propagating at 10% per year. It is now assumed that improvements in the probability of detection under the new rule will assure detection of these cracks at 30% through-wall. The improvement of the detection capability will allow the possibility for the detection of this flaw over an extra inspection cycle. In this projection there will be two conditional assessments made prior to possible SG tube rupture versus one inspection for the existing practice. This should increase the population of degraded tubes which are removed from service prior to a defective condition. This improvement in SGTR frequency does not apply for other causes of tube failure (such as plug release or loose parts damage).

- One improvement is in the ability to discriminate the mode of degradation which is detected. This discrimination is important in the modeling for tube performance. This is a more complex quality of the examination to draw from the performance demonstration and is not explicitly called for in the current guidance.

  The assumption here is that any detected flaw will either be absolutely determined (by destructive sample if necessary), or alternatively will be assumed as the most challenging possible mechanism of degradation. The effect of this will be seen in the analytical part of the program and is not treated here, except to say that a consequence of the new regulation is either an absolute determination of degradation mode, or a conservative assumption of that mode.

- The last improvement is in the enhanced capability for measuring the size of each type of flaw. This comes from the statistical nature of the performance demonstration.

  The quantification of the measurement capability of flaw size for each mode of damage is most critical for the modeling of degradation. It is assumed that this enhancement, which is empirical and derived from real flaw populations, will be slightly better than currently available and will continually improve. This analysis assumes that the quantification process is the key benefit for the reduction in tube failure probability, and that refinements from the process will be small at first and in the order of 10%. The effect of improvement in this area is found in the modeling of degradation.

Effect of Condition Monitoring Assessment

Conditional monitoring assessment is made to confirm that adequate SG tube integrity has been maintained since the previous inspection. It involves an assessment of the "as found" condition of the SG tubing relative to the SG tube integrity performance criteria. The assessment may utilize information from the inspection or from alternative test/examination methods to evaluate the condition of the SG tubing. This element will provide a continuous check on the effectiveness of the program by a look at the performance of the operational assessment over the last cycle. This effectively is the regulator on the process, such that the design envelop of the program is maintained where the design target is no tube ruptures.

The condition monitoring assessment will provide the basis for focusing sample location, sample size, and applying alternate inspection technologies. It is believed that this part of the RG guidance is critically influential on the effect of the programs to reduce SGTR. Condition monitoring assessment is effectively a means to proactively, as opposed to reactively, identify required and beneficial changes in a SG tube integrity assurance program. The condition monitoring assessment goes hand-in-hand with the operational assessment and points the direction of necessary change to provide a continually valid approach for the operational assessment. The two of these together will lower the probability of SGTR.

Tube structural integrity may be monitored against deterministic criteria by analysis based upon the results of NDE inspection, or by alternative means (such as "in-situ" pressure testing) for each degradation mechanism. In-situ pressure testing refers to hydrostatic pressure tests performed on installed tubing in the field. The purpose of these tests is to demonstrate that the subject tubing satisfies the structural and accident induced leak rate performance criteria.

According to the staff guidelines, data from in-situ pressure testing may be used to develop empirical probability of leakage (POL) and conditional leak rate models as a function of NDE indicated flaw size parameters and thus, provide a basis for condition monitoring by analysis. Allowing licensees the option of using this alternative approach provides greater flexibility in making the assessment of the "as-found" condition of the SG tubes.

Effect of Operational Assessment

This is the key ingredient of the program. This is the projected assurance of the integrity of the SG tubes in the next inspection interval. In concert with the steerage provided by the conditional monitoring assessment, the Operational Assessment should be capable over several inspection cycles of providing the target level of reduction in SGTR. This is possible because the knowledge of the flaw state is empirically determined with statistical bounds. The performance requirements then are subjected to the conservatism of modeling (as measured in the conditional monitoring assessment) and fuzziness of the inspection data (as measured by the performance demonstration).

The enhanced measurement and modeling of flaw state will provide a rational basis for future inspections to meet the design targets of the program. If for instance, a 50% improvement in detection provides an additional cycle of inspection, then inspecting all the tube locations subject to that degradation mechanism will reduce the probability of a rupture by more than a factor of 1/4 (because the probability of detection goes up with flaw size). If the rationalized reduction of probability of tube rupture is not to a target level by virtue of sample size, then either an increased frequency of inspection, or an improved NDE technique must be used.

Effect of Optimization of NDE

The effect of optimization of NDE will come from enhancements which are above and beyond those which would occur without the incentives in the new RG. The optimization of NDE will occur over time and the detection capabilities will be most improved, with some lesser improvements in sizing and discrimination of mode of damage. This analysis assumes that the improvements will be realized five years after implementation of the program and that the order of improvement will correspond to 10% improvements in sizing and discrimination and 20% in detection. However, a target reduction in SGTR is believed to be available now with existing inspection and analytical approaches. Improvements in NDE (and modeling for that matter) will only enhance the performance of the SGs.

Effect of Alternative Repair Criteria

Enhancements in repair criteria are thought to have more of an economic rather than a safety significant impact. An important item is that safety margin is maintained with any new application of repair technology. This area is challenging in that there have been some problems with failures in repairs, so that the programs must be constructed to avoid these problems. We feel that this will be done at the same level of effectiveness as that provided by the assessment of the tubing flaw state, so that this area will neither negatively nor positively impact the SGTR probability.

Effect of Primary-to-Secondary Leakage Monitoring

The objectives of primary-to-secondary leakage monitoring are to provide clear, accurate, and timely information pertaining to SG tube integrity as in the following:

- to indicate loss of tube leakage integrity to allow remedial actions to be taken to prevent tube rupture.

- to facilitate the mitigation of any tube failure event.

Tracking primary-to-secondary leakage provides a means of monitoring the integrity of the reactor coolant pressure boundary via the SG tubes, and SG tube degradation during plant operation. SG tube ruptures are to be avoided as they can significantly challenge reactor

safety systems, and orderly plant response and shutdown actions that concern public health and safety. Draft RG X.XX proposes several actions to reduce the occurrence of a SGTR. These include secondary water chemistry program (C.7.1), program for monitoring and control of loose parts (C.7.2), and measures by licensees to mitigate active degradation mechanisms (C.7.3). Many licensees have for the most part already implemented these measures in varying degrees. It is uncertain as to how much additional improvement would be achieved through these measures. Another measure deals with new or replacement SGs which is an ongoing practice by utilities when deemed the best action to be taken in a degraded SG situation.

The TS for all PWR plants include allowable leakage limits set at levels that if not exceeded, should allow for acceptable operator and plant system operations before complete SG tube failure would occur. Section C.8.2 of the draft RG X.XX, proposes that the operational leakage should not exceed 150 gallons per day from any one SG. Some current TS include this leakage limit but not in all cases.

Primary-to-secondary leakage monitoring cannot prevent spontaneous rupture of a SG tube. However, even in such extreme cases, information that would be provided to the operators from such monitoring capability would be of value to responding promptly and effectively to actions that would mitigate the consequences of such failures. This includes suitable training of the operators on effective monitoring. Primary-to-secondary leakage monitoring can be effective in maintaining acceptably low levels of leakage, and reducing the probability of spontaneous SG tube rupture if early stage leakage levels and trending were followed. Thus, primary-to-secondary leakage monitoring plays an important role in the management of SG tube degradation to help reduce the probability of spontaneous tube rupture.

Primary-to-secondary leakage monitoring enhances the capability to detect the following:

- low level and slowly changing primary-to-secondary leakage and,
- rapidly changing primary-to-secondary leakage.

In order to accomplish the above, near real-time data are required to provide the operators with accurate information for them to make the proper response to ensure plant safety. Radiation Monitoring Systems (RMS) are used in current plants to detect and locate leakage sources and levels. RMS provides continuous on-line monitoring capability. In addition, plant sampling is also necessary to verify performance of the RMS and confirm leakage estimates.

Based upon EPRI guidelines (EPRI TR-104788), most plant RMSs include the following:

- Condenser Off Gas Radiation Monitors,

- SG Blowdown Radiation Monitors, and

- Main Steam Radiation Monitors (Noble gas and N-16).

While most plants today have the above capabilities to varying degrees, such capabilities did not always exist. For example, N-16 monitors were used on a commercial basis in the early 1980's based upon discussions with vendors. This becomes important in making an estimate of some benefits that may be realized by the imposition of an effective primary-to-secondary leakage program based on the EPRI guidelines developed by the industry.

The basis for the assessment of benefits that may result from the utilization of the proposed EPRI guidelines for an effective primary-to-secondary leakage program is derived from the operating history of PWRs and spontaneous SG tube failures. In this regard, the following establishes the historical basis:

Plant	Date of SGTR
Point Beach 1	2/75
Surry 2	9/15/76
Prairie Island 1	10/79
Ginna	1/25/82
North Anna 1	7/15/87
McGuire 2	3/17/89
Palo Verde 2	3/14/93

Given that there were three SGTRs in the 1970 decade, at a time when plants did not have the newer technology available for primary-to-secondary leakage monitoring (such as using N-16 monitors), it is not unreasonable to consider that one of these events could have been avoided (or mitigated before complete SG tube failure occurred) with the newer state-of-the art primary-to-secondary leakage monitoring system, all other things being equal. No benefits were ascribed for any of the later events. With these assumptions, the probability of a spontaneous SGTR would be reduced from 7 SGTR in 1500 reactor years (4.7×10^{-3}) per reactor year, to 6 SGTR in 1500 years of reactor operation (4.0×10^{-3}) a reduction of about 15%. This is a conservative estimate that takes credit for the EPRI guidelines on primary-to-secondary leakage monitoring capability which the industry is expected to endorse. Thus, improving primary-to-secondary leakage monitoring can lead to beneficial results in reducing the probability of SG tube rupture.

APPENDIX D: Summary Impacts for Steam Generator Rule

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Appendix D
Summary Impacts for SG Rule

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Delta Impact Subject: Tube Inspections

Source of Impact: Section C.1 of RG X.XX

Table Designation: +ΔInd: More Inspection Time

Delta Impact identification: ΔC-1-1

Discussion of Issue

The new rule will require more refined approaches for qualification of NDE techniques through a performance demonstration. The requirement of application of specific techniques for specific degradation mechanisms will be more engaging than under the current regulations. Most of the development work for inspecting for specific damage mechanisms has been initiated. The history of the industry indicates successful efforts in minimizing the outage times associated with inspections.

Discussion of Assumptions

The assumptions made are as follows:

- The average cycle for inspection is 1.5 years and the average outage costs per day is $800K or 533K per year.
- There will be no impact in inspection outage time caused by enhancements in inspection technology under the new rules.

Discussion of Supporting Data

The industry's experience with existing enhanced inspection technology is used as a basis for the assumptions.

Data Summary Table

+ΔInd.: More Inspection Time	One time costs of impact in $K	Uncertainty in one time savings in $K	Continuing (e.g., mainten.) cost in $K/year	Uncertainty in continuing cost in $K/yr.
Δ per plant	NA	NA	533	+0 -270
Δ for whole PWR industry	NA	NA	38,900	+0 -20,000

Continuing cost: 1 day per inspection cycle per plant x 2/3 cycle per year x $800K per day for replacement power = $533K per year per plant and $38,900K per year for the industry.

Delta Impact Subject: Tube Inspections

Source of Impact: Sections C.1.2, C.1.2.1 and C.1.2.2 of RG X.XX

Table Designation: +Δ_{Ind}: NDE Technique Performance Demonstration Protocol

Delta Impact Identification: Δ_{C-1-2}

Discussion of Issue

The new rule will require a demonstration of all NDE techniques on real samples. The qualification will require a protocol which is adequate to assure a measurement of the ability of techniques to detect, characterize, and size flaws. The probability of detection as well as a statistical basis for sample size will need to be established for all techniques which are credited for use on steam generator tubes.

There is an experience and protocol for a performance demonstration for NDE on the reactor vessels, piping, and fasteners under ASME Section XI, Appendix VIII inspections. Technical elements for approaches and samples are already established for steam generator tubing for a performance demonstration. However the protocol will have to be created from existing elements and tested.

The delta for the industry is limited to the cost of creating and validating the protocol for a performance demonstration of NDE for steam generator tubes. On going cost of performance demonstrations are captured in Δ C.1.3 and Δ C.1.4.

Discussion of Assumptions

The assumptions made are as follows:

- The PWR portion of the nuclear industry will fund the performance demonstration under the administration of EPRI. However, we do not believe that large parts of this funding will be undertaken by EPRI.
- Based on the costs from the ASME Section XI Appendix VIII-Performance Demonstration, we expect that the cost for a full performance demonstration for SG tubing would be about \$6 to 10M, or an average cost of \$8M with an uncertainty of about 25%.
- The continued cost of the performance demonstration is treated separately.
- Cost can be directly attributed to implementing the rule.

Discussion of Supporting Data

The industry experience with the PDI for the ASME Section XI, Appendix VIII is used as a basis for the assumptions as well as discussions with EPRI personnel. We recognize that steam generator NDE studies by EPRI and others have already provided bases for a comprehensive protocol.

Data Summary Table

$+\Delta_{Ind}$: NDE technique performance demonstration	One time costs of impact in $K	Uncertainty in one time cost in $K	Continuing cost in $K/year	Uncertainty in continuing cost in $K/yr.
Δ per plant	+110	+/- 27	NA	NA
Δ for whole PWR industry	+8,000	+/- 2,000	NA	NA

One time cost: $8,000K for the industry or $110K per plant

Delta Impact Subject: Tube Inspections

Source of Impact: Positions C.1.2, C.1.2.1 and C.1.2.2 of RG X.XX

Table Designation: $+\Delta_{Ind.}$: NDE Technique Qualification

Delta Impact Identification: Δ_C-1-3

Discussion of Issue

The new rule will require more refined approaches for qualification of NDE techniques using the performance demonstration protocol (Δ_C-1-2). These technique qualifications will be more extensive than required under the existing rule, and the complexity of the types of NDE will be increased to reflect degradation specific examinations.

Discussion of Assumptions

The assumptions made are as follows:
- Grading units will be needed for NDE Technique Qualification. We assume that 20 grading units each will be required for each degradation mechanism. This will require 54 pulled tubes at a cost of about $200K per tube pulled.
- We assume a possibility of a 20% uncertainty in costs.
- The inspection cycle is 18 months at an annual cost of about $20K per plant. The cost may exceed the $20K by 50%.
- We assume an additional annual cost of engineering time to monitor and control programs elements associated with NDE Technique Qualification at 40 hours a year at $100 per hour.
- There are 59 affected plants (equivalent)
- Cost can be directly attributed to implementing the rule.

Discussion of Supporting Data

The industry experience with NDE inspections has been used, as well as personal experience.

Data Summary Table

$+\Delta_{Ind}$: NDE technique qualification	One time costs of impact in $K	Uncertainty in one time savings in $K	Continuing (e.g., mainten.) in $K per year	Uncertainty in continuing cost in $K/yr.
Δ per plant	+ 183	+/- 36	+ 20	+ 10 - 0
Δ for whole PWR industry	+ 10,800	+/- 2,124	+ 1,180	+ 590 - 0

One time cost: $200K for each of 54 tube pulls = $10.8M for 59 plants.

Continuing cost: Inspection cycle @ 18 months @ an annual cost of about $20K per plant or $1,180K for 59 plants.

Delta Impact Subject: Tube Inspections

Source of Impact: Sections C.1.2, C.1.2.1 and C.1.2.2 of RG X.XX

Table Designation: $+\Delta_{Ind.}$: NDE Qualification of Personnel

Delta Impact Identification: $\Delta_{C\text{-}1\text{-}4}$

Discussion of Issue

The new rule will require more refined approaches for qualification of NDE personnel using the performance demonstration protocol($\Delta_{C\text{-}1\text{-}2}$) These qualifications will be more expensive than required under the new rule. These qualifications will be renewed periodically as under the current regulations.

Discussion of Assumptions

The following assumptions were made:

- The cost per year of qualifying inspection personnel at $200k/year per vendor team of SG tubing examiners.
- The vendor will distribute the additional costs of qualification work among the plants.
- Each inspection team will examine about 6 plants per year and that each plant steam generator will be inspected on an eighteen month cycle.
- The program costs are typical for this type of activity and could be 50% higher.
- Cost can be directly attributed to implementing the rule.

Discussion of Supporting Data

The industry experience with NDE inspections has been used, as well as personal experience with steam generator examinations.

Data Summary Table

$+\Delta_{Ind}$: NDE qualification of personnel	One time costs of impact in $K	Uncertainty in one time savings in $K	Continuing (e.g., mainten.) costs in $K/yr	Uncertainty in continuing cost in $k/yr.
Δ per plant	NA	NA	+22	+11 -0
Δ for whole PWR industry	NA	NA	+1,602	+810 -0

Continuing cost: The cost per year is the 2/3 x (annual qualification costs/team) / 6 plants per year per team = $22K/plant and 73 plants x 22K/plant = $1,602K for the industry.

Delta Impact Subject: Performance Criteria Commensurate with Adequate Tube Integrity

Source of Impact: Section C.2 of RG X.XX

Table designation: $+\Delta_{Ind}$: Model Development

Delta Impact Designation: Δ_{C-2-1}

Discussion of Issue

RG X.XX calls for either a deterministic or a probabilistic assessment (the utility can select one or the other) of the potential for tube failures between inspections. If the chosen method yields acceptable results for tubes of a certain degradation condition, then plugging of those tubes may be deferred until such time as the criteria for them are not met. Current procedures (See Generic Letter 95-05) call for voltage based procedures, and the industry has developed voltage based criteria for burst pressures. EPRI publications include several data bases for degradation specific mechanisms which consider specific materials (i.e., forms of Alloy 600), and operating environments.

Each utility would be required to develop plant specific models, using staff engineers, owner's group resources, and the vendor (or an equivalent provider). It will be assumed that the initial model is generically developed -for example, by an owner's group or utility consortium. If the plant-specific application of the model does not conform to RG guidance, then NRC approval would require further review and evaluation by the NRC. Modeling would be specific to each plant and the bases for the modeling is already established. The NRC requires that the models be subject to verification with every inspection outage, along with an update of the projected growth. This may be accomplished with occasional pulled-tube exams. However, engineering mechanics will probably be employed for most model verification.

Discussion of Assumptions

The assumptions made are as follows:

- The model will have a generic bases, much of which is developed.
- Model development is estimated to be $14,600K.
- There is a 25% uncertainty in the costs.
- Cost can be directly attributed to implementing the rule.

Discussion of Supporting Data

For each plant, there is a very significant one-time cost to develop the models, and apply them for the first time. Knowledgeable industry sources suggest that the model cost will be on the order of $200K/plant.

Data Summary Table

+Δ Ind: Model Verification	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g. maintenance) cost, in $K/year	Uncertainty in continuing cost, in $K/year
Δ per plant	+200	+/- 50	0	NA
Δ for whole PWR Industry	+14,600	+/-3,650	0	NA

One time cost: $200K per plant for model development.
$200K per plant x73 plants = $14,600K for industry

Delta Impact Subject: Condition Monitoring Assessment

Source of Impact: Section C.3, D.1 and D.2 of RG X.XX

Table designation: +Δ_{Ind}: Cost to Perform Assessment

Delta Impact identification: $\Delta_{C\text{-}3\text{-}1}$

Discussion of Issue

Position C.3. of RG X.XX requires that the as-found condition of tubing be monitored during each inspection, whether scheduled or unscheduled, to confirm that the tubes meet the performance of Position C.7. If performance criteria have not been met the NRC should be promptly informed and corrective actions implemented in accordance with Position C.10. For restart following primary-to-secondary leak. This assessment need only address the specific degradation mechanism causing the leak. However, the assessment must address two viewpoints: structural integrity performance, and accident leakage performance:

Discussion of Assumptions

The assumptions made are as follows:

- The additional requirements under the new rule will be incremental from the current approaches. The extra analytical cost is estimated to be half of the cost of the modeling for each plant.
- The uncertainty is estimated to be 25%.
- Cost can be directly attributed to implementing the rule.

Discussion of Supporting Data

The effort required to maintain the performance assessment work is estimated to be half of the development cost for the model verification and the basis of the cost is contained in $\Delta_{C\text{-}2\text{-}1}$.

Data Summary Table

+Δ_{Ind}: Cost to Perform Assessment	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g. maintenance) cost, in $K/year	Uncertainty in continuing cost, in $K/year
Δ per plant	NA	NA	100	+/-25
Δ for whole PWR Industry	NA	NA	7,300	+/-1,825

Delta Impact Subject: Condition Monitoring Assessment

Source of Impact: Sections C.3 and D.1 of RG X.XX

Table designation: +Δ_{Ind}: Prepare Topical Report

Delta Impact identification: ΔC-3-2

Discussion of Issue

The proposed rule will require that the "as-found" condition of the tubing be monitored during each inspection. A description of the methodology to be used in this monitoring process must be submitted as part of a report to the NRC following completion of the condition monitoring assessment. The description of the methodology used it assess the condition of the SG tubes and its technical bases may be described in a topical report that accompanies to the report. A cost effective means of satisfying this requirement for submitting the methodology to the NRC is for the industry, through NEI, to develop a generic topical report which will provide a recommended methodology for use by individual utilities. If the individual utility poses no exception to the recommended methodology, no further submittals to the NRC will be required of that utility. The development of the topical report will have an impact on industry.

Discussion of Assumptions

The assumptions made are as follows:

- The topical report will cover both the structural integrity and the leakage integrity (both operational leakage and accident leakage) monitoring of SG tubes.
- One topical report will adequately describe a recommended methodology that can be embraced by all licensees.
- The document will be approximately 100 pages at $5000 per page.
- The topical report will be generic and applicable to all types of plants supplied by all three nuclear steam suppliers and the various model and makes of SGs.
- Technology improvements will necessitate a revisions to the topical report; the revisions will result in a continuing annual expenditure of industry resources of 10 percent of the effort to develop the initial topical report.
- The cost of this effort can be attributed directly to implementing the proposed rule.

Discussion of Supporting Data

Judgment, based on personal experience.

Data Summary Table

+$\Delta_{Ind.}$: Prepare Topical Report	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	NA	NA	NA	NA
Δ for whole PWR industry	500	+/- 100	50	+/-10

One time cost: 100 pages x $5K per page = $500K
Continuing: 0.1 x $500K = $50K

Delta Impact Subject: Condition Monitoring Assessment

Source of Impact: Sections C.3 and D.1 of RG X.XX

Table designation: +ΔNRC: Review Topical Reports

Delta Impact identification: ΔC-3-3

Discussion of Issue

The proposed rule will require that the "as-found" condition of the tubing be monitored during each inspection. A description of the methodology to be used in this monitoring process must be submitted to the NRC. A cost effective means of satisfying this requirement is for the industry, through NEI, to develop a generic topical reports which will provide a recommended methodology for use by each licensee. If NRC chooses to review the topical reports there will be a one-time impact on staff resources.

Discussion of Assumptions

The assumptions made are as follows:

- Industry will submit five generic topical reports which will describe a recommended methodology for monitoring the condition of the SG tubing in all plants. Therefore, individual licensees will not have to submit individual descriptions to the NRC.
- Individual licensees will not take exceptions to the industry generic topical reports.
- The topical reports will be significant documents consisting of about 100 pages each.
- Technology improvements will necessitate a revisions to the topical reports; approval of the revisions will result in a continuing annual expenditure of NRC staff resources of 10 percent of the effort to review and approve the initial topical report.
- If the NRC staff chooses to review the topical report, it will expend 300 person-hours in reviewing each topical report.
- NRC will also seek laboratory assistance in reviewing the topical report. The laboratory task will cost 100K.
- Person-hour cost of NRC staff effort is estimated at $100/hour.
- The cost of this review effort can be attributed directly to implementing the proposed rule.

Discussion of Supporting Data

No supporting data; based on personal experience.

Data Summary Table

+ΔNRC: Review Topical Report	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	NA	NA	NA	NA
Δ for whole PWR industry	650	+/- 65	50	+/- 5

One-time: 300 person-hours x $100 per person-hour +100K x 5 = $650K
Continuing: 0.1 x $100K x 5 = $50K

Delta Impact Subject: Condition Monitoring Assessment

Source of Impact: Sections C.3.3, C.3.4.3, and D.1.b of RG X.XX

Table Designation: +Δ_{Ind}: In-situ Pressure Testing

Delta Impact Identification: $\Delta_{C\text{-}3\text{-}4}$

Discussion of Issue

The proposed rule allows for the conduct of in-situ hydrostatic pressure tests performed on installed tubing as a way of satisfying "the structural and accident-induced leak rate performance criteria in C.2.0." In-situ pressure testing involves pressurizing at the flawed sections of SG tubing which have been characterized as damaged by various mechanisms (such as degradation or NDE). The test pressure selected must result in a stress state which is bound by the actual stress states during normal and accident conditions corrected for temperature effects, bending stresses and constant factors, and multiplied by an appropriate factor of safety. In a parallel version of the in-situ pressure test using an appropriate differential pressure, the leakage rate through a through-wall defect can be evaluated and compared to specified allowable leakage rates for the given condition and make-up capabilities of the plant. Utilities will use the less expensive in-situ pressure test to confirm tube integrity as related to eddy current sizing rather than relying totally on tube pulling. However, tube pulls would still be required for confirmation of the degradation mechanism(s) and for addressing degradation specific management issues.

Discussion of Assumptions

- Each tube plugging vendor crew is monitored by one staff engineer, one health physicist, and one quality assurance inspector during the procedure.
- Five tubes tested per shift, three shifts to complete set-up, testing, and cleanup of ten tubes.
- In a given outage, ten tubes would be pressure tested resulting in a cost of $110,000.
- Cost can be directly attributed to implementation of the rule.
- An EPRI report describing the procedure exists now, and is likely to be revised and improved in the near term.
- For implementation of RG X.XX, no additional cost for procedural development, utility implementation, or NRC approval is assumed necessary.

Discussion of Supporting Data

- Industry sources have indicated that the cost for conducting in-situ pressure testing would be $90,000 for setup and about $2,000 per tube tested.

- Different vendors have different approaches to the conduct of leakage test (either together with, or followed by the burst test). This results in a greater than normal uncertainty (+/- 20%) in the continuing costs.

Data Summary Table

+ΔInd.: More Inspection Time	One time costs of impact in $K	Uncertainty in one time savings in $K	Continuing (e.g., maintenance) cost in $K/year	Uncertainty in continuing cost in $K/yr.
Δ per plant	N/A	N/A	78K	+/- 15K
Δ for whole PWR industry	N/A	N/A	5,700K	+/- 1,100K

One time costs; None

Continuing cost: $110,000 for ten burst/leakage tests. Assume these costs would be incurred at each refueling/inspection cycle, or twice each three years, or about $73K per year per plant. We assume that 100% of the plants will select this procedure in the next ten years.

Staff time for three workers x three shifts x $100 /hr/worker = 3 x 24 x $100 = $7,200. This would also be incurred twice each three years, equaling approximately $5K per year with little uncertainty.

Then, [$73K + 5K] x 73 = $5,700K for all plants

Delta Impact Subject: Operational Assessment

Source of Impact: Sections C.4, C.6 and D.1 of RG X.XX

Table Designation: +$\Delta_{Ind.}$: Impact on Operation

Delta Impact Identification: $\Delta_{C\text{-}4\text{-}1}$

Discussion of Issue

The new rule will generate additional requirements for inspection and assessment and measurement. Within sixty days after inspection, RG X.XX calls for an assessment demonstrating that the performance criteria of C.4 will be met until the next inspection interval. Any corrective actions per section C.6 must be assessed for effectiveness.

For requirements following a primary-to- secondary leak this assessment is limited to the mechanism causing the leak. However, the assessment must address structural integrity performance, and accident leakage performance. This may generate requirements which do not now exist.

There may be consequences to operations under the new rule which are not currently required such as power reduction and different shut down criteria on leakage.

Discussion of Assumptions

The assumptions made are as follows:

- There will be a relatively incremental improvement in the state of knowledge of the SG tube integrity which will affect 10% of the SGs with increased requirements. These requirements will result in a day per year of lost power production with additional inspection, and analysis costs of $250K per inspection cycle of 18 months ($170k/year).
- We assume the average replacement power cost per day is $800k.
- Note that this is the expense side of this delta and does not examine the benefits, which are discussed in Δ C-4-4.
- We assume an uncertainty of about 30%.
- These changes will represent additional costs to the industry and are a direct consequence of the new rule.

Discussion of Supporting Data

The industry has been proactive in seeking and accepting new approaches to technology for inspection and analysis. The consequences of the application of the new rule making are difficult to assess. Our approaches are based on our experience.

Data Summary Table-Operational Costs

$+\Delta_{Ind}$: Cost of additional requirements	One time costs of impact in $K (for 7.3 plants)	Uncertainty in one time savings in $K	Continuing (e.g., mainten.) cost in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	NA	NA	970	+/-300
Δ for whole PWR industry	NA	NA	7,081	+/- 2,190

Continuing cost: Replacement power costs + Cost of additional inspections and analysis
$800K + $170K = $970K per plant and 970 x 73 plants x 0.10 = $7,081K

Delta Impact Subject: Operational Assessment

Source of Impact: Sections C 4.0, C.1.0, and C.3 of RG X.XX

Table Designation: $+\Delta_{Ind.}$ Operational Assessment: Cost to Perform

Delta Impact Identification: Δ_{C-4-2}

Discussion of Issue

The new rule may generate additional requirements for inspection, testing, and assessments, and there will be new costs associated with the implementation of the "look ahead" or operational assessments for tubing meeting the performance criteria. The "look ahead" assessments are a requirement specific to the new rule. The operational assessment will incorporate the data from inspection and the accepted modeling to project the adequate performance of tubing in the next inspection interval.

Discussion of Assumptions

The assumptions made are as follows:

- The scope of the new rule that there will be an equivalent of one half person year per year expended on the analysis required to support the future performance of SG tubing.
- The person involved in this work will cost $1~~2~~00k per year.
- An uncertainty of 25% in the amount of time required for the look ahead assessments.
- These additional costs to the industry will only occur under the new rule.

Discussion of Supporting Data

We are using personal experience for the basis of this analysis.

Data Summary Table

$+\Delta_{Ind}$: Additional Requirements	One time costs of impact in $K (for 7.5 plants)	Uncertainty in one time savings in $K	Continuing (e.g., mainten.) cost in $K/year	Uncertainty in continuing cost in $K/yr.
Δ per plant	NA	NA	100	+/- 25
Δ for whole PWR industry	NA	NA	7,300	+/- 1,825

Continuing cost: One half person-year x $200K per year = $100K per plant or $7,300K for the industry

Delta Impact Subject: Operational Assessment

Source of Impact: Sections C.4 and C.3 of RG X.XX

Table designation: $-\Delta_{Ind}$: Avoid Unplanned Shutdowns

Delta Impact identification: $\Delta_{C\text{-}4\text{-}3}$

Discussion of Issue

The proposed rule will require increased monitoring of the condition of SG tubing. A better management of the specific degradation mechanisms involved with SG tubing will result in the improved ability to predict conditions that could lead to severe tube leakage and to SGTR. The improved ability to recognize conditions that could result in tube failure, more specific performance criteria to measure tube structural and leakage integrity of SG tubing, and the requirement to perform an operational assessment to predict tube integrity and flaw growth over the next operational cycle will reduce the likelihood tube leakage or tube rupture that could cause an unplanned shutdown. Lowering the frequency of unplanned shutdowns would result in a saving (cost that results from loss of use of the unit and cost to repair the leaking or ruptured tube).

Discussion of Assumptions

The assumptions made are as follows:

- A annual forced outage rate of 0.1 forced outages was assumed This was derived from 1985-1994 EPRI data
- Over the next 10 years expect a 75% reduction in the forced outage rate due to industry efforts, independent of the rule (this was derived from comparison of the reduction in the average annual forced outage rate from the 1985 through 1994 when compared to the same figure for the period 1976 through 1984).
- Each forced outage shutdown is of a 18 day duration.
- Loss of use of the unit results will cost of $800K per day.
- The cost of additional NDE of SG tubes is $200K per force outage.
- The cost savings realized from a reduced frequency of unplanned shutdowns can be attributed directly to implementing the proposed rule.

Discussion of Supporting Data

The following data were derived from the EPRI Steam Generator Progress Report (Revision 11) November 1995:

- For the period, 1985 to 1984 the average forced outage rate was 0.1 forced outages per generating PWR (one forced outage for every 10 generating plants. During that same period the average number of forced outages was 5.6 per year.
- For the period, 1976 to 1985 the average forced outage rate was 0.32 forced outage per generating PWR. During that same period the average number of forced outages was 13.2 per year.
- Excluding the Palo Verde 2 shutdown of March 1993 (105 days duration), the average forced outage duration for the period 1993 through 1994 was 18 days.

Data Summary Table

$-\Delta_{Ind}$: Avoid unplanned shutdowns	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	NA	NA	NA	NA
Δ for whole PWR industry	NA	NA	(-) 80,000	+/- 20,000

Loss of use: Avg. annual forced outage rate x percentage attributed to rule x number of plants in PWR population = forced outage reduction due to rule
0.1 avg. forced outages per year x 73 plants = 7.3 forced outages per year
Forced outage reduction per year x avg. length of each forced outage x $K per day = annual savings attributed to proposed rule
5.48 plant outages per year x 18 days per outage x $800K/day = $78,900K per year

Inspection costs: $200K per outage x 5.48 plant outages per year = $1,100 K per year

Total annual savings: $78,900K + $1,100K = $80,000

Delta Impact Subject: Operational Assessment

Source of Impact: Sections C.4, C.1.3.2, and C.3 of RG X.XX

Table Designation: -ΔInd.: Altered Inspection Cycles

Delta Impact Identification: ΔC-4-4

Discussion of Issue

Current regulations require that inservice inspections be performed at intervals between 12 and 24 months. The inspection intervals are increased or decreased depending on the results found. The results are categorized in three categories that specify the extent of degradation and the number of defective tubes. Depending on the results of the inspection the interval may either be decreased to 20 months or extended to 40 months.

The proposed rule contains no specific inspection frequency requirement. Rather, it requires that the inservice inspections be performed at a frequency as needed such that the operational assessment in accordance with position C.4 demonstrates that performance criteria will continue to be met prior to the next scheduled inspection of the SG.

The proposed rule will require increased monitoring of the condition of SG tubing. A better management of the specific degradation mechanisms involved with SG tubing will result in the improved ability to predict the structural and leakage integrity of the SG tubing. The requirement to perform an operational assessment to predict tube integrity and flaw growth over the next operational cycle also will provide a better foundation upon which to judge the length of the operational cycle that could be achieved without the risk of unacceptable tube leakage or tube structural failure. Extending the operational cycle would result in reduced cost to the industry.

It is possible in some cases that the more refined definition of flaw state of the SG tubing will require more frequent and more extensive examinations.

Discussion of Assumptions

The assumptions made are as follows:

- As a result of the improved tube monitoring and inspection programs and advances in inspection technology, the operational cycle is extended 18 months from an 18-month cycle to a 36 month cycle.
- Each shutdown to inspect tubes results in an inspection cost of $3M.
- The duration of each planned inspection outage from is four weeks.
- The inspection time controls the length of the outage 12 days.
- One out of every five plants will have relatively new steam generators and will be able to take advantage of an extended inspection cycle.
- Loss of use of the unit results will cost of $800K per day.
- Cost can be directly attributed to implementing the rule.
- The cost of an increase in examination frequency is offset by the savings from increase in operational reliability.

Discussion of Supporting Data

No supporting data. These projections are based on personal experience.

Data Summary Table

$-\Delta_{Ins}$: Altered Inspection Cycles	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	NA	NA	2,300	+/- 670
Δ for whole PWR industry	NA	NA	33,600	+/- 10,000

Over a 3 year period there be a savings of 2 outage days and a reduction of one inspection period.
Total annual savings for each unit would be:
(2 days x $800K per day + 1 insp. period x $3,000K per insp. period)/3 years = $2,300K
Total annual savings for whole industry would be:
1/5 x 73 plants = 14.6 plants x $2,300K per plant = $33,600K

Delta Impact Subject: Operational Assessment

Source of Impact: Sections C.4 and D.1 of RG X.XX

Table designation: +ΔInd: Develop Topical Report

Delta Impact identification: ΔC-4-5

Discussion of Issue

The proposed rule will require that an operational assessment be performed within 60 days of plant restart from each SG inspection outage to demonstrate that the performance criteria. will continue to be met until the next scheduled SG inservice inspection. The methodology to be used in this operational assessment process must be submitted to the NRC a part of a final report to be submitted after the completion of the operational assessment. A cost effective me... of satisfying this requirement for submitting the methodology to the NRC is for industry, through NEI, to develop a generic topical report which will provide a recommended methodology for use by individual utilities. The development of the topical report will have an impact on industry resources.

Discussion of Assumptions

The assumptions made are as follows:

- The topical report will be a significant document consisting of about 100 pages.
- Each page of the report will cost $5000
- Technology improvements will necessitate revisions to the topical report; the revisions will result in an annual cost of 10% of the cost of the initial report
- The cost of this review effort can be attributed directly to implementing the proposed rule.

Discussion of Supporting Data

We are using personal experience for the basis of this analysis.

Data Summary Table

+ΔInd: Develop Topical Report	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	NA	NA	NA	NA
Δ for whole PWR industry	500	+/- 100	50	+/-10

One time cost: 100 pages x $5K per page = $500K
Continuing: 0.1 x $500K = $50K

Delta Impact Subject: Operational Assessment

Source of Impact: Sections C.4 and D.1. of RG X.XX

Table designation: +ΔNRC: Review Topical Reports

Delta Impact identification: ΔC-4-6

Discussion of Issue

The proposed rule will require that an operational assessment be performed within 60 days of plant restart from each SG inspection outage to demonstrate that the performance criteria will continue to be met until the next scheduled SG inservice inspection. The methodology to be used in this operational assessment process must be submitted to the NRC. A cost effective means of satisfying this requirement for submitting the methodology to the NRC is for industry, through NEI, to develop a generic topical reports which will provide a recommended methodology for use by individual utilities. If NRC chooses to review the topical report there will have an impact on NRC resources.

Discussion of Assumptions

The assumptions made are as follows:

- Industry will submit five generic topical reports which will describe a recommended methodology for conducting an operational assessment of the SG tubing in all plants. Therefore, individual licensees will not have to submit individual descriptions to the NRC.
- Individual licensees will not take exceptions to the industry generic topical reports.
- The topical reports will be a significant document consisting of about 100 pages.
- Technology improvements will necessitate a revisions to the topical reports; approval of the revisions will result in a continuing annual expenditure of NRC staff resources of 10 percent of the effort to review and approve the initial topical reports.
- If the NRC staff chooses to review the topical report, it will expend 300 person-hours in reviewing the topical report.
- NRC will also seek laboratory assistance in reviewing the topical reports. The laboratory task will cost 100K.
- Person-hour cost of NRC staff effort is estimated at $100/hour.
- The cost of this review effort can be attributed directly to implementing the proposed rule.

Discussion of Supporting Data

We are using personal experience for the basis of this analysis.

Data Summary Table

+ΔNRC: Review Topical Report	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	NA	NA	NA	NA
Δ for NRC	650	+/- 65	50	+/- 5

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One-time: 300 person-hours x $100 per person-hour + i00K x 5 = $650K

Continuing: 0.1 x $100K x5 = $50K

Delta Impact Subject: Operational Assessment

Source of Impact: Sections C.3.1, C.4.1 and D.1 of RG X.XX

Table designation: +Δ_{Ind}: Additional Documentation

Delta Impact identification: ΔC-4-7

Discussion of Issue

The new rule will requires more record-keeping on the part of each licensee. This record-keeping will take the form of additional documentation of the state of degradation of the tubes. Under the current rule, depth of the indication is the only significant parameter (for ODSCC voltage reading are required, but this parameter is another form of depth measurement). The new rule requires that the length and width of the indication be recorded in order to monitor the progression of degradation to ensure that each tube will still meet performance criteria at the end of its next operational cycle.

Discussion of Assumptions

The assumptions made are as follows:

- A 10 page procedure will be developed to manage the required documentation. The procedure development will result in cost of $5000 per page.
- One-time procedure development would be required for all PWRs. However, instead of using a total of 73 units to compute the cost of procedure development, a total of 59 units was used to reflect savings that might be achieved for utilities with more than one unit at a given site.
- The additional documentation will require 1500 person-hours per unit of effort over each operational cycle. A total of 73 units was used to calculate the continuing cost to industry since documentation will be required for each unit.
- The operational cycle will be of an 18 months duration (from startup after a planned shutdown until shutdown for the next planned outage).
- One person-year of effort will cost $200K
- Costs can be directly attributed to implementing the rule.

Discussion of Supporting Data

Mostly judgment and past experience used in developing the impact.

Data Summary Table

+Δ Ind: Additional Documentation	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	50	+/- 10	100	+/- 30
Δ for whole PWR industry	2,950	+/- 590	7,300	+/- 2,190

One-time cost: 10 pages x $5,000 per page = $50K
$50K x 59 plants = $2,950K
Continuing costs: 1500 person-hours per cycle x $100 per person-hour/ 1.5 cycles per year = $100K
$100K x 73 plants = $7,300K

Delta Impact Subject: Condition Monitoring and Operational Assessment

Source of Impact: Section D of RG X.XX

Table Designation: $+\Delta_{NRC}$: Review Conditional Monitoring and Operational Assessment Reports

Delta Impact identification: $\Delta_{C\text{-}4\text{-}8}$

Discussion of Issue

Draft Regulatory Guide X.XX requires a description of the condition monitoring assessment and operational assessment, including methodology and results be provided for each degradation mechanism. Such reports would be expected to be provided by each licensee within 90 days of plant restart from each steam generator inspection outage. Most likely, the staff would review such reports on a one-time recurring basis for each plant.

Discussion of Assumptions

The assumptions made are as follows:

- Licensees will submit reports each year for one-third of the plants.
- Each report will be technically detailed in coverage concerning the results obtained from the inspection and the ensuing evaluation as submitted to the NRC.
- Staff review time is estimated to be 3 person weeks (technical) and 3 person weeks (PM) for a total of 6 person weeks (or 240 hours) @ $100 per hour.
- Assistance from the Labs will not be required except for unusual cases.
- The cost of this review effort can be attributed directly to implementing the proposed staff action.
- Cost determination made on a continuing basis.

Discussion of Supporting Data

No supporting data; based upon personal experience and judgment.

Data Summary Table

$+\Delta_{Ind.}$: More Inspection Time	One time costs of impact in $K	Uncertainty in one time savings in $K	Continuing (e.g., mainten.) cost in $K/year	Uncertainty in continuing cost in $K/yr.
Δ per plant	NA	NA	8	+/- 1
Δ for NRC	NA	NA	585	+/- 60

Delta Impact Subject: Tube Plugging and Repairs

Source of Impact: Section C.5.1, C.1.0 and C.1.1 of RG X.XX

Table designation: $+\Delta_{Ind}$: Prepare ARC Topical Reports

Delta Impact identification: ΔC-5-1

Discussion of Issue

Currently, the guidance for tube repair (plugging and sleeving) is based on a 40% through wall repair criterion. This guidance is prescriptive and absolute, being based on the measured depth of the flaw indication; it is independent of the mode of degradation and the flaw geometry. The proposed guidance, while still allowing the use of the 40% through wall criterion as a default repair method, will also permit application of alternate repair criteria (ARC) to determine acceptable methods of repair based on the type and geometry of the degradation mechanism found. The ARC allow analytical approaches to assess the criticality of flaws (flaw type, flaw propagation rates, and the impact on tube integrity to upset and normal operating conditions These ARC are described in SGDSM strategies which together with their technical bases are documented in technical reports. The industry has already been preparing such reports for the SGDSM program.

Discussion of Assumptions

The assumptions made are as follows:

- The industry will support and coordinate a compilation of existing and new ARC through its ongoing SGDSM program.
- Comprehensive topical reports will be prepared to cover all current and future ARC.
- EPRI will administer and support these activities, but will not fund these efforts. We believe that virtually all PWR owners will participate in funding of this topical document.
- These topical reports will be reworked and reissued within five years based on an improved experience base and higher levels of understanding of tube degradation which will be a consequence of the new Regulatory Guide approach.
- No additional costs can be directly attributed to implementing the rule since this effort would most likely occur regardless of whether the rule existed.

Discussion of Supporting Data

Discussions with EPRI and industry personnel indicate the probable need to repackage and extend existing reports and information in this area.

Data Summary Table

+ΔInd.: Prepare Topical Reports	One time cost of impact in $K	Uncertainty in one time cost in $K	Continuing (e.g., mainten.) cost in $K/year	Uncertainty in continuing cost in $K/yr.
Δ per plant	NA	NA	NA	NA
Δ for whole PWR industry	0	NA	0	NA

Delta Impact Subject: Tube Plugging and Repairs

Source of Impact: Section C.5.1, C.1.0 and C.1.1 of RG X.XX

Table designation: +ΔNRC: Review ARC Topical Reports

Delta Impact identification: ΔC-5-2

Discussion of Issue

Currently, the guidance for tube repair (plugging and sleeving) is based on a 40% through wall repair criterion. This guidance is prescriptive and absolute, being based on the measured depth of the flaw indication; it is independent of the mode of degradation and the flaw geometry. The proposed guidance, while still allowing the use of the 40% through wall criterion as a default repair method, will also permit application of alternate repair criteria (ARC) to determine acceptable methods of repair based on the type and geometry of the degradation mechanism found. The ARC allow analytical approaches to assess the criticality of flaws (flaw type, flaw propagation rates, and the impact on tube integrity to upset and normal operating conditions These ARC are described in SGDSM strategies which together with their technical bases are documented in topical reports. These topical reports which will be developed by industry groups and submitted to the NRC for information. Following review, if the topical reports do not deviate from the NRC guidance, no approval by the NRC will be necessary. Any exceptions to NRC guidance will require NRC approval. Even though no approval is required, NRC will still want to review these topical reports. The initial review and the approval of any exceptions will have an impact on NRC staff resources.

Discussion of Assumptions

The assumptions made are as follows:

- There will be five topical reports which will cover the ARC. These reports will cover the specific degradation mechanisms that have been or will become evident during future plant operations.
- In total, the reports will consist of about 750 pages.
- The topical reports submitted by the industry would not contain exceptions to NRC guidance. However, each topical report will require updating within five year to account for improvements in inspection and analysis techniques.
- Even though approval is not required, NRC will want to do an cursory review of each report and updating revisions, and an in-depth review of exceptions taken by individual licensee.
- The initial review will have an impact on NRC resources of 600 hours per report. Updating reviews will take the same time.
- Staff person-hour cost is $100 per hour; contractor cost (Lab) set at $200K each report.
- Costs can be directly attributed to implementing the rule.

Discussion of Supporting Data

Mostly judgment used in developing the impact.

Data Summary Table

+ΔNRC: Review Topical Reports	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	NA	NA	NA	NA
Δ for NRC	1300	+/- 125	260	+/- 25

Initial: 5 [(600x100) + 200K] = $1300K

Continuing Costs: 5 [600 x 100) + 200K] / 5 = $ 260K per year

Delta Impact Subject: Tube Plugging and Repairs

Source of Impact: Sections C.5.1, C.1.0 and C.1.3 of RG X.XX

Table designation: -Δ_{Ind}: Technical Specifications Changes

Delta Impact identification: ΔC-5-3

Discussion of Issue

The TS specify frequency of inspection and sample size based on the defects found in the SGs. The current rules also allow for the application for TS changes based on degradation specific analyses of flaws for variations in rejection criteria. These submissions are prepared for and processed by the NRC. We understand that currently there are six of these plant specific technical specifications which have been approved and about 12 more which are pending. Under the old rules these technical specifications are made on a plant specific basis. Under the new rule there will be new TS requirements. Along with the standard rule there will be some few plant specific items included with the TS changes.

Discussion of Assumptions

The following assumptions were made:

- Under the current rule TS changes to account for ARC would require submittal for the 73 plants.
- These submittals would occur over the next ten years. The average industry cost for a TS change is about five personnel months at $83k and additionally, contractor costs typically of about $100k.
- The proposed rule would permit the licensees to submit much less complicated TS amendments based on meeting the guidance of the proposed RG X.XX. Application for a standard TS amendment with minor plant specific items is assumed to cost a half of what is anticipated under the current rules.
- Cost saving can be directly attributed to implementing the rule.

Discussion of Supporting Data

The only supporting data concern the experience to date. The industry will take advantage of the ability to be less restrictive in repair criteria with the requirement of a technical basis for this augmented approach.

Data Summary Table

ΔInd.: TS Changes	One time savings of impact in $K (for 73 plants)	Uncertainty in one time savings in $K	Continuing (e.g., mainten.) cost in $K/year	Uncertainty in continuing cost in $K/yr.
Δ per plant	NA	NA	NA	NA
Δ for whole PWR industry	13,400	+/-135	NA	NA

One time savings: ($83K + $100K) x 73 = 13,400K.

Delta Impact Subject: Tube Plugging and Repairs

Source of Impact: Sections C.5.1, C.1.0 and C.1.3 of RG X.XX

Table designation: -ΔNRC: Technical Specification Changes

Delta Impact identification: ΔC-5-4

Discussion of Issue

The TS specify frequency of inspection and sample size based on the defects found in the SGs. The current rules also allow for the application for TS changes based on degradation specific analyses of flaws for variations in repair criteria. The proposed rule will eliminate the need for TS changes as a means of handling specific degradation mechanisms found in SGs for plants that can demonstrate acceptable risk. The NRC staff will not have to review TS amendment submitted for individual plants to address specific degradation mechanisms (if risk has been shown to be acceptable). Instead, the NRC will issue standard TS to conform to the new rule. Industry will apply the standard TS to individual plants and issue plant-specific technical specifications. However, these TS will be generic in nature, and will not require staff review to address specific degradation mechanisms due to the proposed staff action.

Discussion of Assumptions

The assumptions made are as follows:

- The use of topical reports to handle specific degradation mechanisms found will eliminate the need for individually tailored plant TS amendments. This would eliminate need to review and approve TS amendments to cover all the assumed degradation mechanism when risk is shown to be acceptable.
- In place of the process of reviewing individual plant TS amendments, the NRC will issue generic standard TS to address the requirements of the new rule. These standard TS will be generic in nature, and therefore, will apply to all PWRs.
- Cost can be directly attributed to implementing the rule. The judgment is that the net impact is 0 and that an equal number of plants will be able to show risk is acceptable, saving review cost as plants that would submit TS changes with risk assessments.

Discussion of Supporting Data

Mostly judgment and past experience used in developing the impact.

Data Summary Table

-ΔNRC: Reduced Technical Spec Changes	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	NA	NA	NA	NA
Δ for NRC	0	NA	NA	NA

One-time cost: Since TS need to be changed for any ARC, there is no impact due to the proposed staff action already in place.

Delta Impact Subject: Tube Plugging and Repairs

Source of Impact: Sections C.5.0, C.5.1 and C.5.2 of RG X.XX

Table designation: -Δ_{Ind}: Changes in Tubes Plugged

Delta Impact identification: Δ_{C-5-5}

Discussion of Issue

Current TS require tube repair (plugging and sleeving) when degradation reaches or exceeds 40% through wall (50% in a few special cases), or projection of degradation indicates the tube would rupture when subjected to a 3 x ΔP transient prior to the next outage. The new rules will allow continuation of power production, utilizing tubes with flaw indications, even those with greater than 40% through wall indications, as long as tubes will safely survive upset pressure transients (i.e., 3 x ΔP) which might occur before the next inspection. Projection of flaw growth can be made with degradation specific algorithms. This discussion presents an estimate of actual plugging costs.

Discussion of Assumptions

- Assume that the current plugging rate is about 25 tubes per year per SG
- Assume 12 additional tubes will be plugged due to applications of advanced NDE.
- Assume that new guidelines would allow 12 tubes per SG to be deferred to the next year for low risk plants.
- The $42,000 setup fee is not recoverable, since we will assume that some tubes would be plugged.
- Each plugging vendor crew is monitored by one staff engineer, one health physicist and on quality assurance inspector during the procedure.
- The plugging operation proceeds at a rate of about three plugs per hour.
- Cost can be directly attributed to implementing the rule.

Discussion of Supporting Data

The following supporting data was obtained from industry sources:

- Industry sources quoted a price for tube plugging of a $42,000 setup, and $1,200 per plug. These are the prices for the plugging vendor.
- The number of defective tubes due to SCC/IGA was 50% of total number of plugged tubes (EPRI-Steam Generator Progress Report 11, November 1995).
- EPRI data (Steam Generator Progress Report 11) states that 6400 tubes were plugged in 1994 due to SCC/IGA defects in a total of 241 SGs.

Data Summary Table

-Δ Ind: Changes in Tubes Plugged	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g. maintenance) cost, in $K/year	Uncertainty in continuing cost, in $K/year
Δ per plant	+ 49	+/- 5	NA	NA
Δ for whole PWR Industry	+ 3,590	+/- 360	NA	NA

Twelve tubes not plugged saves $14,400, plus 1.65 hours of staff time for three people, adding another $500 for a total of $14,900 saved per year, per generator. $14,900 per generator x 241 generators = $3,590K for the whole industry or $49K per plant. This is a one-time savings, since eventually these tubes will be plugged.

Delta Impact Subject: Tube Plugging and Repairs

Source of Impact: Sections C.5.0, C.5.1, C.4.1.1 and C.4.1.2 of RG X.XX

Table Designation: -Δ Ind.: Increased Flexibility for SG Tube Replacement

Delta Impact Identification: ΔC-5-6

Discussion of Issue

The current assessment techniques and plugging criteria are used to maintain each steam generator to the point of retirement. A number of plants will have to replace steam generators, and virtually every operating PWR faces the potential of SG replacement. A part of this sensitivity comes from the uncertainty and expense of maintaining an old SG generator with a number of plugged and degraded tubes. The new rule provides the operation of a steam generator for a longer period than could be tolerated under the current rule by using analytical techniques and qualified data. For instance, tubes may be kept operable for certain modes of degradation if analysis shows the performance criteria is maintained for those tubes within the next operating cycle. This extension of tube operation may provide a longer operating life for some generators. Although this option will allow for extension of operation prior to the resolution of replacement vs. shut down for some plants, the most prevalent approaches indicate that companies will replace steam generators as soon as possible.

Discussion of Assumptions

The assumptions made are as follows:

- We assume that there may be occasions when plants will defer the replacement of steam generators under the new rule.
- There is also the possibility that the assessments under the rule will cause a more aggressive schedule for steam generator placement. This is assumed to be of advantage in terms of operational reliability.
- We assume that any advantage in deferred replacement will be offset by early replacement under the guidance of this rule
- There is no benefit attributed to implementing the rule.

Discussion of Supporting Data

EPRI (1994 report) data show that 33 SGs out of a total of 241 SGs are scheduled for replacement over five years (6.5 SGs per year).

Table

-Δ Ind: Increased flexibility for SG tube replacement	One time savings of impact in $K (for 6 plants)	Uncertainty in one time savings in $K	Continuing (e.g., mainten.) cost in $K/year	Uncertainty in continuing cost in $K/yr.
Δ per plant	NA	NA	NA	NA
Δ for whole PWR industry	0	NA	NA	NA

Delta Impact Subject: Reports to NRC

Source of Impact: Section D of RG X.XX

Table Designation: +ΔNRC: Initial Review of Technical Specification

Delta Impact identification: ΔC -5-7

Discussion of Issue

The staff would prepare and issue sample TS to the industry that pertain to implementation of the provisions of draft RG X.XX. Subsequently, the licensees using the sample TS as a basis, would prepare plant unique TS and submit them to the staff for review and approval. The principal areas that will be covered in the revised TS include LCOs and Surveillance requirements for SG tube integrity, SG tube operational leakage, and reactor coolant activity limits. The efforts involved with this impact pertain to the staff review and processing the individual initial TS amendment requests submitted by each licensee.

Discussion of Assumptions

The assumptions made are as follows:

- Each licensee would submit a TS amendment request (73 in all) to comply with the provisions of RG X.XX.
- Staff review efforts would be on the order of 300 hours per TS amendment.
- Staff cost on an hourly basis would be at $100 per hour.
- This is a one-time action.
- The cost of the review can be attributed directly to implementing the proposed staff action.

Discussion of Supporting Data

No supporting data; based on personal experience and technical judgment.

Data Summary Table

+ΔNRC - Review of Initial TS	One time costs of impact in $K	Uncertainty in one time savings in $K	Continuing (e.g., mainten.) cost in $K/year	Uncertainty in continuing cost in $K/yr.
Δ per plant	30	+/- 3	NA	NA
Δ for NRC	2,190	+/- 200	NA	NA

Estimated based upon: (300 hours per plant @ $100 per staff hour) x 73 plants = $2,190K or $30K per plant

Delta Impact Subject: Preventive Measures

Source of Impact: Section C.7 of RG X.XX

Table Designation: $+\Delta_{Ind}$: Prepare Program Topical Report

Delta Impact Identification: Δ_{C-7-1}

Discussion of Issue

This section states that preventative measures should be developed and implemented to minimize the potential for tube degradation and to mitigate active degradation mechanisms. Because of the new program for SG tube integrity assurance utilizing a performance-based and risk-based rule, it is anticipated that industry will prepare comprehensive topical reports to implement a program incorporating the guidance given in draft R G X.XX. This effort most likely would be undertaken with funding and guidance of an owner's group with coordination by NEI and EPRI.

Discussion of Assumptions

There are two scenarios which are examined. First there is the possibility that the existing reports sponsored by EPRI and NEI are adequate to be incorporated with changes to align these documents with the Reg. Guide requirements. There is a second scenario which suggests a complete rework of existing reports for a program topical report which provides the details for the implementation of a steam generator program under the new rule. We have assumed that the NRC staff will perform a cursory review of the topical report to verify that all elements are covered. Such a review will not have a significant impact on staff resources. The assumptions of these two scenarios follow:

Major use of existing documents:

- The topical(s) to be developed would be quite comprehensive and responsive to the guidance pertaining to performance-based and risk-based SG tube integrity assurance rule and draft R G X.XX.
- The topical report would incorporate 80 pages of existing documentation. Changes and new material would account for 20 pages of material.
- In all cases the estimated average cost per page is $5,000.

Major rework of existing documents:

- The topical(s) to be developed would be quite comprehensive in responding to the guidance pertaining to performance-based and risk-based SG tube integrity assurance rule and draft R G X.XX.
- The topical report would be 100 pages in length, and that an initial draft would be issued for comment and later revised for the final report.
- Based on the data from the Shutdown Rule, the cost estimate for the topical report is set at $5,000 per page.
- Cost in both cases can be directly attributed to implementing the rule.

Discussion of Supporting Data

Mostly judgment based in developing the impact and relying upon the data from the Shutdown Rule.

Data Summary Table

Using existing documentation.

$+\Delta_{Ind}$: Prepare topical report	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	N/A	N/A	N/A	NA
Δ for whole PWR industry	100	+/- 10	N/A	NA

One time cost: 20 pages x $5K per page = $100K

Reworking all existing documentation.

$+\Delta_{Ind}$: Prepare topical report	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	N/A	N/A	N/A	NA-
Δ for whole PWR industry	500	+/- 50	N/A	NA

One time cost: 100 pages x $5K per page = $500K

Delta Impact Subject: Operational Primary-to-Secondary Leakage Monitoring/Limits

Source of Impact: Sections C.8.1 of RG X.XX

Table designation: +ΔInd: Hardware/Installation Cost

Delta Impact identification: ΔC-8-1

Discussion of Issue

This issue pertains to monitoring of primary-to-secondary leakage for early detection capability of developing SG tube failure. Section C.8.0 of RG X.XX indicates that a monitoring strategy should use an array of methods to detect and measure leakage, and indications should be available to control room operators.

> The leak rate monitoring program for primary-to secondary system leakage should detect the onset of SG tube failures before sudden and complete SG tube rupture occurs. Such capability should include the following:
>
> a. Diverse instrumentation which can detect reasonably low leak rate levels, discern changes in leak rate, and which provide timely and accurate information to operators in the control room.
>
> b. Operational limits including trend limits, based on instrumentation capabilities and timely but reliable indication of true leak rate.
>
> c. Procedures that include well defined actions for escalating levels of leak rate under all modes of plant operation.
>
> d. Operator training to properly use available control room indications to discern leak rate trends.
>
> e. Procedures for defining how quickly the plant should be brought to cold shutdown depending on the rate of leakage and rate of leakage increase.

The above guidelines are similar to those under consideration by the EPRI industry task group and reported in the EPRI guidelines (TR-104778). These are in agreement with the objectives stated in the draft Regulatory Guide X.XX - provide clear accurate, and timely information (1) indicating loss of tube integrity to allow remedial actions to be taken to prevent tube rupture; and, (2) to facilitate the mitigation of any tube failure event.

While the TS include primary-to-secondary leakage limits for SGs, there are no specific requirements for such monitoring even though RG 1.45 calls for such capability. The TS focus mainly on the monitoring of the containment atmosphere and sump levels for leakage monitoring. No clearly stated and specific requirements were evident in several sets of TS examined that pertain to monitoring capabilities for primary-to-secondary leakage monitoring that would implement the guidance given RGs 1.45, 1.83, and 1.97.

There are shortcomings in the implementation of primary-to-secondary leakage monitoring measures pertaining to the capability for early detection of SG tube leakage at levels below tube rupture leakage. Although no single monitor should be expected to fulfill all

monitoring roles, some monitoring methods have demonstrated particular value in certain situations. For example, some licensees have installed N-16 monitors to detect the onset of primary-to-secondary leakage. However, while no specific TS requirements appeared in the TS examined, it is generally reasonable to believe that many PWR plants in varying degrees, have installed capability for primary-to-secondary leakage monitoring. In this regard, the following monitoring (either in part, or in total) is believed to exist on many PWR plants. (NOTE: No plant-specific survey was conducted on the family of PWRs, but based upon several documents examined (such as EPRI leakage guidelines, INEL studies, and GEBCO sample plant surveys), this observation appears reasonable.)

- Main steam line monitors (N-16)
- Main steam line noble gas monitors
- Condenser air ejector monitor
- SG blowdown monitor
- Other means include sampling and make-up rate monitors

Discussion of Assumptions

- Most PWRs are believed to have some level of installed capability for primary-to-secondary leakage monitoring along the lines of those identified above.
- Maintenance costs were based on an on-going basis of 24 hours per month; cost was estimated @ $100 per person-hour for this effort.
- Costs were estimated on the basis of 73 PWR plants (51 W, 15 CE, and 7 B&W).
- Installation of hardware made during a scheduled outage.
- Cost can be directly attributed to implementing the rule.

Discussion of Supporting Data

The considerations for this study included a review of RGs 1.45, 1.83 and 1.97 which contain provisions for primary-to-secondary leakage monitoring. In addition, TS for ANO2 and BV1 as well as W STS were reviewed. INEL reports provided by NRR/DSSA were also reviewed where cost data were provided. The cost data used were those derived from an industry survey conducted by GEBCO Engineering under separate contract to assess the impact of complying with the EPRI guidelines on primary-to-secondary leakage.

1. N16 monitors off the main steam lines

On the basis of the survey conducted by GEBCO, upgrade costs for the N16 monitors for a four-loop plant were as follows:

• material	$200K
• engineering	$60K
• labor	$160K
• margin x1.2	$84K
TOTAL	**$504K*** (use $125K per loop)

(* compare to an actual plant estimate of $534K)

For a single plant, a weighted average cost was determined based on the numbers of 2, 3, and 4 loop plants. This was determined to be \$383.7K for a representative single plant for the 73 PWR plant population.

2. Condenser offgas radiation monitor to sample condenser offgas

Costs were found to vary depending upon the modifications required for this installation. An estimated between \$250K and \$300K (or \$275K) was used as obtained from the GEBCO survey. This is considered to be on the high-end based upon major plant modification action.

Combining the costs for the two plant upgrades (N16 and offgas monitoring), the total plant cost becomes \$658.7K. This was used in the summary data table.

GEBCO was also able to make an estimate of the total plant situation as to what would be required by the industry to comply with the guidelines. It is unlikely that there are many (if any) plants that do not have some type of primary-to-secondary leakage monitoring system similar to those described above. It is likely that the action would be more along the lines of upgrading with some replacement hardware. However, a complete survey of the industry would be required to determine the exact situation for each plant (such as control room modifications and plant-specific cable installation aspects). This was not done for this assessment. Thus, the estimates given are considered to be upper limits.

N16 cost for all plants = 73 x 383.7K = 28,010K and 73 x 275K = 20, 075K or a total of 48,000K

On the other hand, for the sensitivity study based on voluntary actions, it was estimated that 66% of the plants do not have N16 monitors with control room indication. Thus, the N16 total cost would be 0.66 x 73 x \$383.7k = \$18.5M. Similarly, 25% of the plants would require condenser offgas upgrade; 0.25 x 73 x \$275K = \$5M. The overall total cost is then estimated to be \$18.5M + \$5M = \$23.5M.

Maintenance costs were @ \$100 per hour for 24 hours per month x12 per year, turns out to be \$28.8K per plant or X 73 plants = approximately \$2.1M total.

Data Summary Table

+ΔInd - Hardware Cost	One time cost of impact, in \$K	Uncertainty in one time cost, in \$K	Continuing (e.g., mainten.) cost, in \$K/year	Uncertainty in continuing cost, in \$K/yr.
Δ per plant	\$658.7	+/- 165	28.8	+/- 7
Δ for whole PWR industry	\$48,000	+/- 12,000	2,100	+/-525

Delta Impact Subject: Operational Primary-to-Secondary Leakage Monitoring/Limits

Source of Impact: Sections C.8.2 of RG X.XX

Table designation: +ΔNRC: NRC Review of Technical Specifications

Delta Impact identification: ΔC-8-2

Discussion of Issue

While TS include leakage limits for SGs, there are no specific requirements for primary-to-secondary leakage detection and monitoring even though RG 1.45 calls for such capability for PWR plants. TS focus is mainly on the containment atmosphere and sump levels. However, SG tube leakage monitoring is not specified. No requirements were found in TS for ANO2, BV1 and W STS that pertain to primary-to secondary leakage monitoring to implement the guidance given in RGs 1.45, 1.83, and 1.97 as well as RG X.XX.

It is anticipated that the staff will develop generic performance-based TS requirements for the primary-to-secondary leakage monitoring systems. These actions include LCOs and Surveillance requirements for the instrumentation systems using the guidelines of RGs 1.45, 1.83, and 1.97 which would become part of the Standard PWR TS.

Discussion of Assumptions

The assumptions made are as follows:

- Based upon past experiences with TS development, the addition of LCOs and Surveillance requirements for STS would involve NRC staff systems and I&C engineers. It is assumed that system requirements could be developed by one person with two months of effort; I&C staff time would be one month. Total staff effort is estimated to be three-person months.
- Some additional staff review time would be required to verify that licensees have adopted the standard TS for their plants and to allow for any minor discussions on unique situations. A total time of one staff month per plant (with due allowances for multiple plant sites and licensee involvement with a number of similar plants) seems reasonable for this aspect.
- Staff time is based upon a rate of $200,000 per person-year.
- There are 59 equivalent PWR plants based on weighted effects for multiple plants on the same site.
- Cost can be directly attributed to implementing the rule.

Discussion of Supporting Data

Supporting data for this delta are based mainly on judgment derived from past experiences in developing and processing TS changes.

Data Summary Table

$+\Delta$NRC: NRC Review of TS	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	17.6	+/- 1.8	NA	NA
Δ for whole PWR industry	1,040	+/- 104	NA	NA

Total effort for this delta for the staff is estimated to be three staff-months plus one staff-month per plant x 59 = 62 staff-months or 5.2 staff-years. Using $200,000 per staff-year, the total cost is $1.04M or $17.6K per plant (equivalent).

Delta Impact Subject: Operational Primary-to-Secondary Leakage Monitoring/Limits

Source of Impact: Sections C.8.1.3 of RG X.XX -

Table designation: $+\Delta_{Ind}$: Maintenance and Training

Delta Impact identification: Δ_{C-8-3}

Discussion of Issue

It is anticipated that licensees will have to develop and update maintenance procedures and requirements for the primary-to-secondary leakage monitoring systems to implement the provisions of RG X.XX. Most likely, many licensees already have such procedures already developed. However, because of the new performance-based maintenance rule (50.65), major revisions are expected. Along with revisions to the maintenance plan, training of licensee staff to new program features would also be required (such primary-to-secondary leakage monitoring and required TS actions). The EPRI guidelines offer some assistance to licensees for training scenarios on various types of SG tube leakage progression.

Discussion of Assumptions

The assumptions made are as follows:

- It is assumed that each licensee would require at least one-person and three months effort on a per plant basis to revise the maintenance procedures pertaining to the primary-to-secondary leakage monitoring systems for their plant; this assumption would be independent of whether there was one or more plants at a given site.
- It was further assumed that the NRC had approved the basic maintenance program submitted under 50.65 in conjunction with its review of the licensee's overall maintenance program; assume 0.5 staff month of effort.
- Training of the staff in the new maintenance program would require two persons and two months of effort (four staff months total) to prepare a new training program, and approximately 20 hours each for two staff persons (40 staff hours total) to conduct the actual training on a per plant basis.
- As was the case for previous assessments involving all plants, an equivalent factor of 59 was used instead of 73 for all PWRs.
- Staff time is based upon a rate of $200,000 per person-year.
- Training and requalification on a yearly basis: 6 persons @ 40 hours each (240 staff hours).
- Cost can be directly attributed to implementing the rule.

Discussion of Supporting Data

The assumptions used for this impact are based upon engineering judgment obtained from past similar experiences.

Data Summary Table

$+\Delta$Ind: Maintenance and Training	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	62	+/- 6	25	+/- 2.5
Δ for whole PWR industry	3,658	+/- 360	1,830	+/- 180

The total effort involves with the initial maintenance program preparation for a single plant is estimated to 3.75 staff-months or 0.31 staff-years. For all plants (on an equivalent plant basis), the total time is of the order of 18.4 staff-years. At $200,000 per staff-year; the single plant cost is $62K or 62K X 59= $3,658K.

For the yearly cost estimate, single plant level of effort is estimated to be 240 staff-hours (or 1.5 staff-months); all plants (not equivalent) effort would be 1.5 X 73=109.5 staff-months. The corresponding staff-year equivalents are: 0.125 staff-years single plant, and 9.125 staff-years for all plants. Using $200K per staff-year, the costs are $25K and $1830K.

Delta Impact Subject: **Radiological Assessment**

Source of Impact: Sections C.9.2.2 and C.9.2.3 of RG X.XX

Table designation: -ΔInd: Technical Specification Changes

Delta Impact Identification: ΔC-9-1

Discussion of Issue

In identifying that the accident leakage performance criterion is met, Section C.9.0 of RG X.XX indicates that licensees may select from either one of two methodologies for calculating the doses from SG tube degradation events. These are (1) Default Methodology, and (2) Flex Methodology. The former is one currently in use by most licensees and incorporates dose calculations utilizing the methodology presented in SRP Sections 15.1.5 and 15.6.3. Licensees using the Default Methodology would not have to perform a dose assessment every inspection cycle.

On the other hand, Regulatory Guide X.XX provides a second alternative, "Flex Methodology." In this case, licensees with SGs which have experienced degradation mechanisms to such an extent that an alternative repair criteria may be applied to the SG tubes. This necessitates that licensees include in their accident assessments the contributions to doses from releases arising from event-induced leakage. Utilizing this methodology incorporates much of the dose assessment methodology contained in SRP Sections 15.1.5 and 15.6.3.

For licensees using the Flex Methodology, a change to their TS will be required. The new TS will contain a figure which is a plot of total leakage, both normal and event induced leakage, as a function of RCS activity and dose equivalent ^{131}I. Such data are described in detail in Section C.9.0 of Regulatory Guide X.XX.

Discussion of Assumptions

The following assumptions were made in assessing the impact delta from this action:

- TS change submission for SG will be made for all 73 PWR plants to adopt the Flex Methodology; an equivalent of 59 to account for multiple plants at same site, and same plant owner utility. However, only 50% of the plants would be affected.
- The average industry cost for a TS change is estimated to be five-staff months of effort or \$83K (@\$200K per person year), and contractor cost of about \$100K.
- Costs would be reduced by about one-half by using STS with minor plant-specific items.
- Cost savings can be directly attributed to implementing the rule.

Discussion of Supporting Data

The supporting data come from experiences to date. The industry will take advantage of the ability to be less restrictive in calculating accident doses based upon actual plant conditions.

Data Summary Table

$+\Delta_{Ind}$ - TS Changes	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	-91.5	+/- 20	N/A	N/A
Δ for whole PWR industry	-2,700	+/- 540	N/A	N/A

One Time Cost: (83K + $100K)*1/2 = $91.5K per plant or $91.5K*59*(0.5) = $2,700K or $2.7M.

Delta Impact Subject: Radiological Assessment

Source of Impact: Section C.9.2.3 of RG X.XX

Table designation: +ΔNRC: NRC Review of Technical Specifications

Delta Impact identification: ΔC-9-2

Discussion of Issue

In identifying that the accident leakage performance criterion is met, Section C.9.0 of RG X.XX indicates that licensees may select from either one of two methodologies for calculating the doses from SG tube degradation events. These are (1) Default Methodology, and (2) Flex Methodology. The former is one currently in use by most licensees and incorporates dose calculations utilizing the methodology presented in SRP Sections 15.1.5 and 15.6.3. Licensees using the Default Methodology would not have to perform a dose assessment every inspection cycle.

On the other hand, Regulatory Guide X.XX provides a second alternative, "Flex Methodology." In this case, licensees with SGs which have experienced degradation mechanisms to such an extent that an alternative repair criteria may be applied to the SG tubes. This necessitates that licensees include in their accident assessments the contributions to doses from releases arising from event-induced leakage. Utilizing this methodology incorporates much of the dose assessment methodology contained in SRP Sections 15.1.5 and 15.6.3. For licensees using the Flex Methodology, a change to their TS will be required. The new TS will contain a figure which is a plot of total leakage, both normal and event induced leakage, as a function of RCS activity and dose equivalent ^{131}I. Such data are described in detail in Section C.9.0 of Regulatory Guide X.XX and would be used when degradation mechanisms appear and total primary-to-secondary is projected to be greater than normal operating leakage.

Discussion of Assumptions

- At some point, each licensee would opt to employ the Flex Methodology and therefore would submit a request for appropriate changes to their TS.
- Based upon past experiences with TS reviews, the addition of LCOs and Surveillance requirements would involve review efforts by the systems and radiological calculations staff. Some I&C effort would also be involved. Accordingly, it is assumed that the review effort would be three staff months for a generic type review that would be applicable for most all plants, plus one staff month of project management for each plant involving the Flex Methodology.
- Staff effort is based on a rate of $200,000 per person year.
- There are 59 equivalent PWR plants based upon weighted effects for multiple plants on the same site and same utility plant owners.
- Cost can be directly attributed to implementing the rule.

Discussion of Supporting Data

Supporting data for this delta are based mainly on judgment derived from past experiences in developing and processing TS changes.

Data Summary Table

+ΔNRC: Review of TS	One time cost of impact, in $K	Uncertainty in one time cost, in $K	Continuing (e.g., mainten.) cost, in $K/year	Uncertainty in continuing cost, in $K/yr.
Δ per plant	17.6	+/- 3.5	NA	NA
Δ for whole PWR industry	1,040	+/- 208	NA	NA

Total effort for this delta for the staff is estimated to be three staff-months plus one staff-month per plant x 59 = 62 staff-months or 5.2 staff-years. Using $200,000 per staff-year, the total cost is $1.04M or $17.6K per plant (equivalent).

Delta Impact Subject: Risk Assessment

Source of Impact: Section C.10 of RG X.XX

Table Designation: +ΔNRC: Review of Industry Risk Assessment

Delta Impact identification: ΔC-10-1

Discussion of Issue

Plants electing to seek the option for ARC would be required to perform a risk-informed study in accord with Draft Regulatory Guide DG-1061. Subsequently, the staff would be required to review these analyses.

Discussion of Assumptions

The assumptions made are as follows:

Cost for the review of each analysis set at 15k per plant.

Discussion of Supporting Data

Based upon judgement on past experiences with the reviews of similar types of risk-informed analyses.

Data Summary Table

+ΔNRC Review	One time costs of impact in $K	Uncertainty in one time savings in $K	Continuing (e.g., mainten.) cost in $K/year	Uncertainty in continuing cost in $K/yr.
Δ per plant	15	+/- 3	NA	NA
Δ for reviews	1,095	+/- 25	NA	NA

Cost @ 15K per plant X 73 = 1,095K total

Delta Impact Subject: Risk Assessment

Source of Impact: Section C.10 of RG X.XX

Table Designation: $+\Delta_{Ind}$: Preparation of Risk Assessments

Delta Impact identification: $\Delta_{C\text{-}10\text{-}2}$

Discussion of Issue

Plants electing to seek the option for ARC would be required to perrorm a risk-informed study in accord with Draft Regulatory Guide DG-1061.

Discussion of Assumptions

The assumptions made are as follows:

It is estimated that the cost to perform the risk-informed analysis for ARC, would be $100k per plant and that all licensees would seek this option.

Discussion of Supporting Data

Based upon judgement on past experiences with similar types of risk-informed analyses.

Data Summary Table

$+\Delta_{Ind.}$: Prepare Risk Assessment	One time costs of impact in $K	Uncertainty in one time savings in $K	Continuing (e.g., mainten.) cost in $K/year	Uncertainty in continuing cost in $K/yr.
Δ per plant	100	+/- 20	NA	NA
Δ for whole PWR industry	7,300	+/- 1,500	NA	NA

APPENDIX E: Draft Regulatory Guide X.XX: Steam Generator Tube Integrity

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DRAFT
REGULATORY GUIDE X.XX

STEAM GENERATOR TUBE INTEGRITY

A. INTRODUCTION

Section 50.XX of 10 CFR Part 50 requires applicants for, and holders of, construction permits and operating licenses for commercial pressurized water reactors to monitor and maintain the condition of the steam generator tubes to provide reasonable assurance that steam generator (SG) tubes remain capable of fulfilling their intended safety functions. The first of these safety functions derives from the fact that the SG tubes are an integral part of the reactor coolant pressure boundary (RCPB), constituting a major fraction of the RCPB surface area. As part of the RCPB, the SG tubes must be capable of maintaining reactor coolant inventory and pressure. Second, the SG tubes serve as a medium for heat transfer between the primary and secondary system, and thus function to ensure the capability to shutdown the reactor. In addition the SG tubing functions to isolate radioactive fission products in the primary coolant system from the secondary system and possible release to the environment. Thus, the SG tubes function to ensure the capability to prevent or mitigate the consequences of accidents that could result in potential offsite doses.

To ensure that these safety objectives are met, 10 CFR 50.XX requires that reasonable assurance of adequate SG tube integrity be maintained and, to ensure defense-in-depth, the means to mitigate occurrences involving abnormal leakage and/or rupture of the tubing are maintained. Adequate tube integrity means that the tubes are capable of sustaining the conditions of normal operation, including anticipated operational occurrences, design basis accidents, external events, and natural phenomena for which the tubing must perform their safety functions and that risk is kept at an acceptably low level.

To provide reasonable assurance of adequate tube integrity, 10 CFR 50.XX requires that NRC accepted performance criteria be established consistent with the general performance criteria requirements in the rule. The approach described in 10 CFR 50.xx incorporates a balance of preventive, inspection and repair, and leakage monitoring measures as necessary to ensure that the performance criteria will be maintained. In addition, the condition of the SG tubes shall be monitored against these performance criteria to confirm adequate tube integrity is being maintained. Monitoring methods shall be as appropriate to allow reliable assessment of tube condition against the performance criteria. 10 CFR 50.XX requires that failure to meet these performance criteria shall be reported to the NRC, and corrective actions shall be implemented, as appropriate, to ensure adequate tube integrity during future operation.

This guide describes an acceptable basis for complying with the requirements of 10 CFR 50.xx through the development of a steam generator program. This guide applies only to pressurized water reactors (PWRs). The Advisory Committee on Reactor Safeguards has been consulted concerning this guide and has concurred in the regulatory position.

B. DISCUSSION

1. Related Regulatory Requirements/Guidance

Section 50.55a, "Codes and Standards," of 10 CFR, Part 50 requires, in part, that structures, systems, and components be designed, fabricated, constructed, and inspected to quality standards commensurate with the importance of the safety function to be performed. Section 50.55a further requires, in part, that throughout the service life of a PWR facility, ASME Boiler and Pressure Vessel Code (ASME Code) Class 1 components meet the requirements, except design and access provisions and preservice examination requirements, in Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," of applicable editions of the ASME Code, to the extent practical. This requirement basically includes the inspection and repair criteria of Section XI of the ASME Code. However, paragraph (b)(2)(iii) of 10 CFR, Part 50.55a, states that where technical specification surveillance requirements for steam generators differ from those in Article IWB-2000 of Section XI of the ASME Code, the inservice inspection program shall be governed by the technical specifications.

General Design Criteria (GDC) of 10 CFR, Part 50, Appendix A, applicable to the integrity of the steam generator tubes include the following:

a. GDC-1, "Quality Standards and Records," states in part that structures, systems, and components important to safety shall be designed, fabricated, and tested to quality standards commensurate with the importance of the safety functions to be performed. ...

b. GDC-2, "Design Basis for Protection Against Natural Phenomena," states in part that structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena without loss of capability to perform their safety functions. ...

c. GDC-4, "Environmental and Dynamic Effects Design Basis," states in part that structures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents and shall be protected against dynamic effects that may result from equipment failures and from conditions and effects outside the nuclear unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analyses reviewed and approved by the NRC demonstrate that the probability of piping rupture is extremely low under conditions consistent with the design basis for the piping.

d. GDC-14, " Reactor Coolant System Boundary," states that the RCPB shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abrormal leakage, of rapidly propagating failure, and of gross rupture.

e. GDC-30, "Quality of the Reactor Coolant Pressure Boundary," states that components which are part of the RCPB shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the source of the reactor coolant leakage.

f. GDC-31, "Fracture Prevention of Reactor Coolant System Boundary," states in part that the RCPB shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperature and other conditions of the RCPB materials and the uncertainties in determining material properties; residual, steady state, and transient stresses; and the size of flaws.

g. GDC-32, "Inspection of the Reactor Coolant Pressure Boundary," states that components which are part of the RCPB shall be designed to permit periodic inspection and testing of important areas and features to assess their structural and leak tight integrity.

10 CFR 50, Appendix B, establishes the quality assurance requirements for the design, construction, and operation of safety-related components. The pertinent requirements of this appendix apply to all activities affecting the safety-related functions of these components; these include, in part, inspecting, testing, operating, and maintaining. Criteria IX, XI, and XVI of Appendix B are particularly noteworthy with respect to the integrity of the steam generator tubing. Criterion IX, "Control of Special Processes", requires that measures be established to assure that special processes such as welding, heat treating, and nondestructive testing are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, etc. Criterion XI, "Test Control", requires in part that a test program be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. Criterion XVI, "Corrective Action", requires in part that measures be established to assure that conditions adverse to quality are promptly identified and corrected.

To ensure that these regulations are met, each applicant's steam generator design and steam generator maintenance and surveillance program are evaluated by the NRC in accordance with the review guidance in NUREG-0800, "Standard Review Plan," before issuing a license. In addition, the NRC reviews the applicant's analyses of the consequences of SG tube leakage and rupture for design basis accidents in accordance with the Standard Review Plan. These analyses must show that radiological consequences to control room personnel are in accordance with GDC-19, "Control Room", and that offsite radiological consequences do not exceed 10 CFR 100 guidelines.

Once the plant is in operation, the licensees are required by the technical specifications to perform periodic inservice inspections of the SG tubing and to repair or remove from service (by installing plugs in the tube

ends) all tubes exceeding the tube repair limit. In addition, operational leakage limits are included in the technical specifications to ensure that should tube leakage develop, the licensee will take prompt action to avoid rupture of the leaking tube(s).

NRC Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," Revision 1, July 1975, provides guidance concerning SG inspection scope and frequency and nondestructive examination (NDE) methodology. This regulatory guide is referenced by the standard review plan (SRP) and is intended to provide a basis for reviewing inservice inspection criteria in the technical specifications. However, this guidance is superseded by this regulatory guide.

NRC Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded Steam Generator Tubes," August 1976, provides guidelines for determining the tube repair criteria and operational leakage limits which are specified in the technical specifications. The repair limit guidelines specifically address depth-based repair limits (i.e., repair limits which specify allowable flaw depth). However, the guidance herein supplements the guidance in RG 1.121 to address alternative types of tube repair criteria (e.g., length-based and voltage-based repair criteria) and to address the treatment of uncertainties and variabilities in tube geometry, material properties, NDE flaw measurements, and flaw growth rates.

2. 10 CFR 50.XX Program Overview

This regulatory guide provides an acceptable framework for complying with the requirements of 10 CFR 50.XX via the development of steam generator programs that provide reasonable assurance that the SG tubes are capable of performing their intended safety functions. This framework incorporates a risk informed, performance-based approach, consistent with 10 CFR 50.XX, for providing reasonable assurance of adequate structural and leakage integrity of the tubing and low risk. This includes performance criteria commensurate with adequate tube integrity, programmatic considerations for providing reasonable assurance that the performance criteria will be met during plant operation, and guidelines for monitoring the condition of the tubing to confirm that the performance criteria are in fact being met.

Figure 1 provides a flow chart illustration of the overall program strategy embodied in this regulatory guide, including each of the major program elements and sub-elements. Figure 1 includes a cross-reference to the sections in Part C of this regulatory guide containing the specific guidance for these program elements and sub-elements.

Specific implementation details and methodologies for these program elements are to be developed by the utilities. This regulatory guide provides broad guidelines concerning the key considerations, parameters, and/or constraints which should be addressed as part of the development of these program elements to ensure that tube integrity performance can be effectively monitored and controlled relative to the tube performance criteria. It is the

intent of these guidelines that licensees have the flexibility to adjust the specifics of the program elements within the constraints of these guidelines to reflect new information, new NDE technology, new degradation mechanisms, changes in flaw growth rates, etc. without NRC review and approval. To this end, these guidelines are intended to accommodate the development and implementation of degradation specific management (DSM) strategies to be documented in industry topical reports. DSM strategies involve an integrated set of program elements, paralleling those in this regulatory guide, which address specific degradation mechanisms.

As shown in Figure 1, the program strategy begins with an NDE tube inspection following plant shutdown in accordance with Section C.1 of this regulatory guide. The inspection is intended to provide information concerning the active degradation mechanisms present in the SGs, the identity of tubes containing flaws and the size of these flaws for each active degradation mechanism, and the rate of flaw evolution for each active degradation mechanism. This information is used as part of other program elements, discussed below, to assess tube integrity performance relative to the tube integrity performance criteria, to determine the appropriate time interval to the next inspection, to determine the appropriate tube repair limits, to determine which tubes fail to satisfy these repair criteria (and which must, therefore, be repaired or removed from service), and to assess needed improvements in measures being taken to mitigate active degradation mechanisms.

With respect to tube inspections in accordance with Section C.1, Section C.1.1 provides guidance for assessing, prior to each inservice inspection, degradation mechanisms which may potentially affect the tubing. This is to ensure that appropriate NDE inspection techniques and personnel are used to address each mechanism. Section C.1.2 provides guidance concerning the development and implementation of NDE data acquisition and analysis procedures for each degradation mechanism. This is to ensure that NDE sizing and detection performance is known and thus can be appropriately accounted for in assessing tube integrity performance relative to the tube integrity performance criteria. Section C.1.2 includes guidance concerning the qualification and performance demonstration of NDE techniques and personnel. Sections C.1.3 provides guidance pertaining to the frequency of inspection and tube inspection sample size. This is to ensure the frequency and scope of inspection is defined in such a manner as to ensure that tube integrity performance is consistent with the tube integrity performance criteria.

The tube inspections are followed by assessments of tube integrity performance relative to NRC accepted performance criteria which are commensurate with adequate tube integrity. Performance criteria acceptable to the NRC are given in Section C.2 of this regulatory guide. These performance criteria address three areas of tube integrity performance; namely structural integrity, operational leakage integrity, and accident-induced leakage integrity. These performance criteria are expressed in terms of parameters which are directly measurable or which may be calculated on the basis of direct measurements. The criteria correspond to conditions under which public health and safety is still assured.

Tube integrity performance is subject to two different types of assessments, as indicated in Figure 1; a condition monitoring assessment in accordance with Section C.3 of this regulatory guide and an operational assessment in accordance with Section C.4. The condition monitoring assessment is "backward looking" in that it's purpose is to confirm that adequate tube integrity has been maintained since the previous inspection. Condition monitoring involves an assessment of the "as found" condition of the tubing relative to the tube integrity performance criteria. The condition monitoring assessment may utilize information from the tube inspections and/or from alternative test/examination methods to assess the condition of the tubing. NRC should be promptly notified in accordance with Section D.2 should condition monitoring reveal one or more tubes that fail to meet the performance criteria. Note that this kind of finding may or may not be indicative of programmatic deficiencies in the licensee's implementation of 10 CFR 50.XX. In addition, licensees should assess the causal factors associated with this type of finding and implement appropriate corrective actions in accordance with Section C.6 of this regulatory guide. The condition monitoring assessment and implementation of resulting corrective actions, if necessary, must be completed prior to plant restart.

The operational assessment differs from the condition monitoring assessment in that it is "forward looking" rather than "backward looking." Its purpose is to demonstrate reasonable assurance that the tube integrity performance criteria will be met throughout the period prior to the next scheduled tube inspection. Operational assessment involves projecting, at an appropriate level of confidence, the condition of the tubing at the time of the next scheduled inspection outage relative to the tube integrity performance criteria. This projection is based on the above-mentioned inspection results, the tube repair criteria to be implemented for each degradation mechanism in accordance with Section C.5.1, and the time interval prior to the next scheduled tube inspection. Corrective actions in accordance with Section C.6 should be taken, as necessary to ensure that the performance criteria are met. Corrective actions may include inspecting the steam generators at more frequent intervals and/or reducing the tube repair criteria. The operational assessment and implementation of resulting corrective actions, if necessary, should be completed within 90 days following plant restart. However, it will generally be necessary to perform at least a preliminary assessment prior to performing tube plugging and/or repairs to ensure that the tube repair criteria being implemented are sufficient to support operation for the planned operating interval preceding the next scheduled steam generator inspection.

Plugging and/or repair of defective tubes is performed in accordance with Section C.5, prior to plant restart, based on the results of the tube inspections and operational assessment. Defective tubes are those with indicated flaws exceeding the tube repair limit. Plugging and/or repair of defective tubes is intended to ensure that tubes remaining in service will meet the tube integrity performance criteria until the next scheduled tube inspection. Section C.5.1 provides guidelines for determining the appropriate repair limits for each degradation mechanism. Determination of the appropriate repair limit is generally performed in parallel with the operational assessment since the outcome of the operational assessment is a

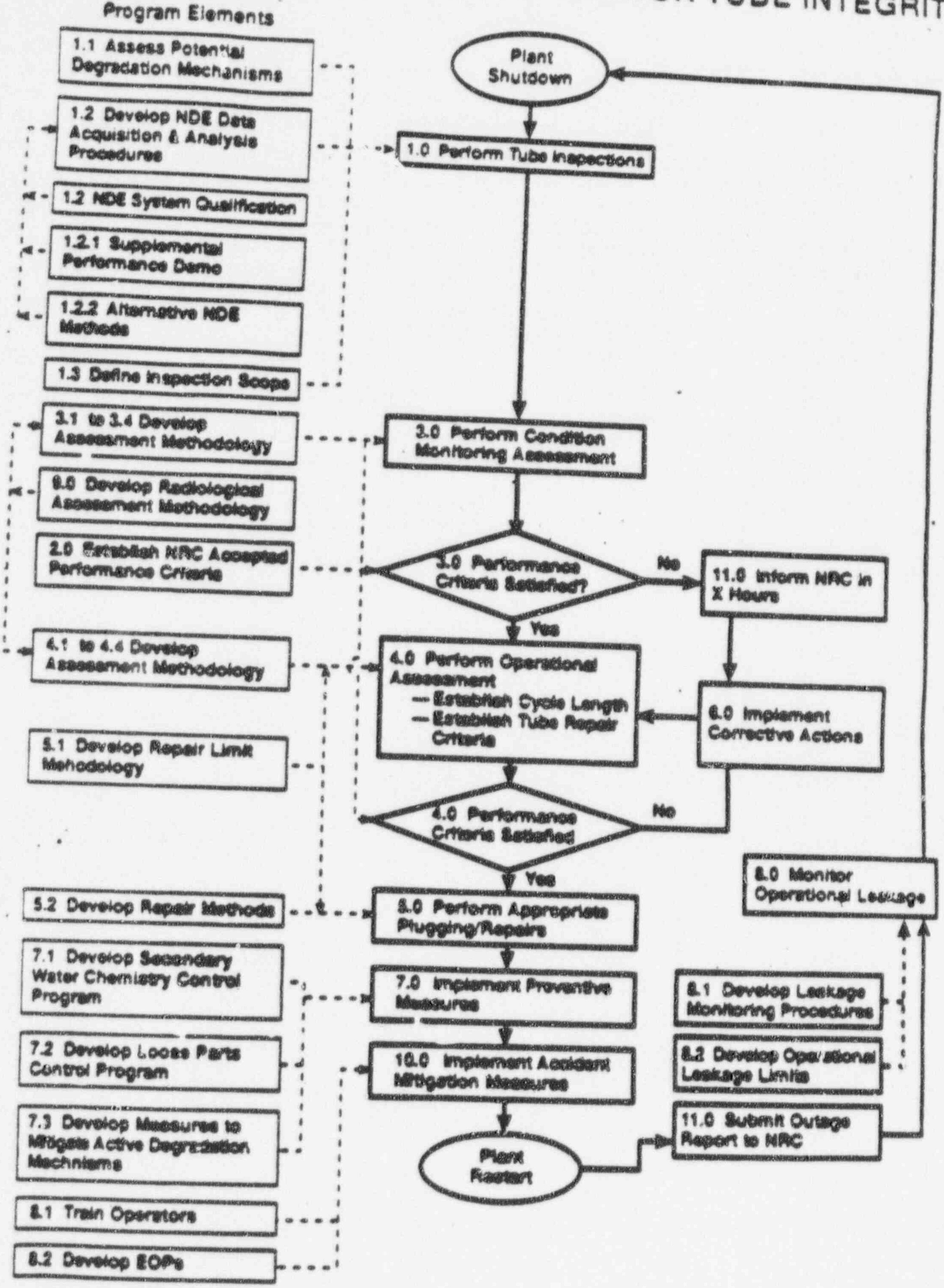
function of the tube repair criteria values to be employed. Section C.5.2 provides guidelines for developing appropriate plugging and repair methodologies, including the associated hardware (e.g., plugs and sleeves).

Preventive measures are implemented in accordance with Section C.7 and involve measures to mitigate active degradation mechanisms and to minimize the potential for new degradation mechanisms. Section C.7.1 addresses secondary water chemistry control. Section C.7.2 addresses measures to control loose parts and foreign objects within the steam generators. Section C.7.3 addresses other measures for mitigating active degradation mechanisms. Various preventive measures are implemented continuously during plant operation and shutdown. The need for enhancements to these measures should be reviewed and implemented, as necessary, based on inspection results and the tube performance assessments.

Operational primary-to-secondary leakage monitoring is performed in accordance with Section C.8. These guidelines are intended to ensure that leakage is effectively monitored and that appropriate and timely action will be taken before a leaking tube exceeds the tube integrity performance criteria, including tubes undergoing rapidly increasing leak rates. Section C.8.1 addresses development of monitoring programs. Section C.8.2 addresses development of allowable limits for operational leakage.

Guidelines for submitting reports to the NRC are provided in Section D.

PROGRAM STRATEGY/STEAM GENERATOR TUBE INTEGRITY



C. REGULATORY POSITION

The guidelines herein provide an acceptable approach for developing a program that meets the requirements of 10 CFR 50.XX. This program should be documented in plant procedures, be auditable, and should conform to 10 CFR 50, Appendix B. Reporting requirements should be in accordance with D.2 of this Regulatory Guide.

C.1.0 Tube Inspections

A steam generator tube preservice and inservice inspection program should be developed and implemented. The objective of the preservice inspection is to establish the baseline NDE response of tubes in new and replacement steam generators and to identify and remove from service or repair any defective tubes prior to initial operation of the steam generators. Defective tubes are tubes containing flaws (as indicated by inservice inspection) which fail to satisfy the applicable repair criterion (see Section C.5.1). The objectives of the inservice inspection program are to (1) identify active tube degradation mechanisms which are present, (2) detect and size tubing flaws, (3) determine the rate of new indications for each active degradation mechanism, (4) determine flaw growth rates for each active degradation mechanism, and (5) remove from service or repair all tubes found to be defective. Knowledge of the active degradation mechanisms is important from the standpoint of (1) identifying potential corrective measures which can be taken to mitigate these mechanisms as discussed in C.7.3, (2) ensuring that the most suitable NDE techniques are applied to address each mechanism as discussed in C.1.2, and (3) determining the appropriate repair limit to apply to each detected indication as discussed in C.5.1. The detection and sizing of flaws are a key objective since this information is needed to (1) determine which tubes contain indications exceeding the appropriate repair limit and which therefore need to be removed from service or repaired, (2) to perform a condition monitoring assessment in accordance with C.3.0 to confirm that performance criteria commensurate with adequate tube integrity are being met, and (3) to perform an operational assessment in accordance with C.4.0 to ensure that these performance criteria will continue to be met prior to the next scheduled inspection. The observed rate of new indications and observed growth rate of old indications (indications observed during the previous inservice inspection in tubes that were left in service and not repaired) for each active degradation mechanism are also needed in order to perform the operational assessment in C.4.0.

The preservice and inservice inspection program should include the following elements and considerations:

C.1.1 Assessment of Potential Degradation Mechanisms

Licensees should assess what degradation mechanisms may potentially affect the steam generator tubes during the steam generator lifetime. The purpose of this assessment is to ensure that inspection techniques and personnel used for the detection and sizing of flaws are appropriate for all potential degradation mechanisms. Degradation mechanisms, in this context,

include the circumstances of the degradation which may affect the appropriate NDE technique(s) which are applicable to that degradation. For example, the circumstances of stress corrosion cracking include (1) whether it initiates from the outer diameter (OD) or inner diameter (ID) surface of the tube, (2) whether it is axially or circumferentially oriented, and (3) the presence of tube or support structure geometric discontinuities, dents, or deposits which may mask defect signals. The assessment for potential degradation mechanisms should be performed prior to preservice inspection of new and replacement steam generators and prior to each scheduled inservice inspection of the steam generators. This assessment should include consideration of plant and steam generator design, materials, and operational practice (e.g., temperature, secondary water chemistry control performance). This assessment should also include consideration of the accumulated service time and degradation experience at the subject plant and at other plants of similar design, materials, and operational practice, as appropriate.

C.1.2 NDE Data Acquisition and Analysis

Licensees should ensure that each organization (e.g., utility or vendor) that conducts SG NDE inspections has a written procedure for conducting NDE data acquisition and analysis. These procedures should be in accordance with the EPRI Steam Generator Examination Guidelines (Reference X) *[subject to staff comments on the EPRI guidelines which were previously provided]*. These procedures should also incorporate the following enhancements and clarifications:

a) The procedures should ensure that NDE techniques used to address each potential degradation mechanism are "validated" for that mechanism and that this validation is applicable to the specific plant. For purposes of this regulatory guide, "validated" techniques are techniques which have been qualified in accordance with the EPRI guidelines (Reference X), Section 7 and Appendix H, and which have undergone supplemental performance demonstration in accordance with C.1.2.1. The technique validation is applicable to a specific plant when the circumstances of the degradation (as defined in C.1.1), noise amplitude (e.g., electrical noise, tube noise, calibration standard noise, deposit noise, dent signals, etc.), and signal-to-noise ratios were representatively included in the EPRI qualification and supplemental performance demonstration test samples. For degradation mechanisms for which there is no validated technique available, non-validated NDE techniques may be used provided that the techniques are qualified for detection in accordance with the EPRI guidelines. In addition, the data acquisition and analysis procedures should ensure that the use of non-validated techniques satisfy the guidelines in C.1.2.2.

Note, NDE technique refers to the specific data acquisition equipment and instrumentation, data acquisition procedures, and data analysis procedures. "NDE technique" in this context includes the summation of techniques directed at each degradation mechanism. For example, the use of bobbin probes for performing an initial screening inspection followed by a rotating pancake coil (RPC) inspection to confirm possible indications found by the bobbin would constitute a single NDE technique for detection purposes.

Also note, NDE detection performance is evaluated in the EPRI guidelines in terms of the probability that a given flaw is detectable, i.e., "probability of detection" (POD), and the percentage of detected flaw indications which in fact are false calls, i.e., false call percentage (FCP). NDE techniques and personnel are "qualified for detection" when the subject performance criteria for POD and FCP in the EPRI guidelines are met. NDE techniques and personnel are "validated for detection" when they are "qualified for detection" and when supplemental performance demonstration in accordance with C.1.2.1 has been completed for detection. NDE sizing performance is evaluated in the EPRI guidelines in terms of the accuracy of NDE flaw size measurements versus actual flaw size. Accuracy is evaluated in terms of root-mean-squared-error (RMSE) for a group of measurements. NDE techniques and personnel are "qualified for sizing" when the subject performance criteria on sizing accuracy in the EPRI guidelines are met. NDE techniques and personnel are "validated for sizing" when they are "qualified for sizing" and when supplemental performance demonstration in accordance with C.1.2.1 has been completed for sizing.

b) The procedure should provide (directly, or by reference) a technique specification for each NDE technique to be employed to address each degradation mechanism. The technique specification should identify the data acquisition equipment and instrumentation, data acquisition and analysis procedures, and values of all essential variables. For qualified/validated techniques, the technique specification should be consistent with what has been qualified/validated in accordance with item a above. In addition, the technique specification should be consistent with the data acquisition equipment and instrumentation, data acquisition and analysis procedures, and values of all essential variables implicit in steam generator degradation specific management (SGDSM) strategies being implemented in accordance with C.5.1 for specific flaw mechanisms.

c) The procedure should ensure that all NDE personnel are "validated" for the NDE techniques to be used and for the degradation mechanisms for which they are being applied. For purposes of this regulatory guide, "validated" personnel are personnel who have been "qualified" in accordance with the EPRI guidelines (Reference X), Section 6 (including site-specific performance demonstration) and Appendix G, and have undergone supplemental performance demonstration in accordance with C.1.2.1. This assumes that the NDE techniques are validated for the subject degradation mechanisms in accordance with item a above. Where this is not the case and a non-validated technique is being employed pursuant to C.1.2.2, the procedures should ensure that the NDE personnel meet the guidelines of C.1.2.2. NDE personnel refers to NDE data analysts and to computerized data analysis systems. Licensees should ensure that the qualification and supplemental performance demonstration records for NDE personnel describe the limits of applicability of the qualification and supplemental performance demonstration and that the NDE personnel are not performing their duties outside these limits of applicability; i.e., the specific NDE techniques and the "application" of these techniques for which the personnel have been validated. "Application" refers to the specific degradation mechanisms to which the subject NDE technique is being applied.

C.1.2.1 Supplemental Performance Demonstration

[The guidelines of the section can be deleted if satisfactorily incorporated into the EPRI guidelines, Appendices G and H. In addition, "qualification" in accordance with the EPRI guidelines also constitutes "validation" in accordance with C.1.2.0 provided the qualification satisfies the supplemental performance demonstration guidelines herein.]

NDE technique and personnel qualification in accordance with the EPRI guidelines (Reference X) ensures a minimum acceptable level of proficiency in the conduct of inservice inspections. However, the detection and sizing performance achieved during the qualification may or may not be fully indicative of the performance that can be expected in the field. For this reason, NDE techniques and personnel should undergo supplemental performance demonstration in accordance with the guidelines of this section to quantify their flaw detection and sizing performance for all potential degradation mechanisms to assess their capability to perform a reliable inspection, to determine the most appropriate NDE techniques for a given application, to identify needed improvements in NDE capabilities, to support the development of alternative tube repair criteria addressed in C.5.1, and to support the condition monitoring and operational assessments addressed in C.3.0 and C.4.0, respectively. POD performance is not considered directly as part of the condition monitoring assessment. However, POD performance should be assessed to ensure its adequacy to identify indications which potentially may fail to meet the structural performance criteria of C.2.a.(1) or which may leak under postulated accident conditions. POD performance is considered as part of the operational assessment and development of tube repair criteria, either directly or indirectly, since the rate and size distribution of new indications that may occur prior to the next scheduled inspection is, in part, a function of POD. Sizing performance is considered directly as part of the condition monitoring assessment, operational assessment, and tube repair criteria development.

For some degradation mechanisms, "relative" sizing performance rather than "actual" (i.e., "absolute") sizing performance may be of interest. This is the case when models for tube structural performance and leakage performance, used for the condition monitoring and operational assessments in C.3.0 and C.4.0, are based on empirical correlations with a measured NDE parameter (e.g., indicated length, depth, and voltage) rather than actual defect geometry (e.g., actual length, depth, width). Relative sizing performance consists of the consistency (i.e., repeatability) of the size parameter response and the consistency (i.e., repeatability) of the analyst interpretation of this response. Absolute sizing performance consists of the accuracy of the NDE size parameter response and the analyst measurement of that response relative to the actual size of the flaw.

Demonstration of NDE relative sizing performance is not subject to the supplemental performance demonstration guidelines of this section. *[It is assumed that the forthcoming revisions to the EPRI guidelines will provide a satisfactory basis for quantifying relative sizing performance. The most immediate need in the EPRI guidelines involves the need for quantifying voltage measurement performance since structural and leakage models have been*

developed which are a function of voltage. If not addressed in the EPRI guidelines, the supplemental performance demonstration guidelines of this section will have to be expanded to address voltage measurement performance.]

Supplemental performance demonstration for NDE techniques and personnel should be performed on a common data set such as to allow overall NDE detection sizing performance to be evaluated against actual flaw geometries. A written protocol for supplemental performance demonstration should be prepared by organizations (utilities or vendors) performing the demonstration. The performance demonstration protocol for data acquisition and data analysis should conform to the EPRI guidelines (Reference X), Appendices G and H, as applicable, subject to the following guidelines:

a) Separate data sets should be employed for each potential degradation mechanism identified in C.1.1. Extraneous signals (e.g., denting, deposits, tube geometry changes, etc) should be included as part of the data sets for each degradation mechanism, as applicable based on SG inservice inspection experience. Note, where such extraneous signals are found to have a significant influence on the detection and/or sizing performance of an NDE technique, the NDE performance demonstrations should be performed to address these extraneous signals consistent with the degree to which these extraneous signals exist in the steam generators to be inspected.

b) Data acquisition with the subject NDE technique should be conducted for the entire data set. Data analysis by individual analysts should be conducted for a portion of the total data set such that the analysts are not tested on identical data sets. The data acquisition and analysis should be blind tests.

c) The total and partial data sets for each degradation mechanism should contain a sufficient number of flawed and unflawed grading units to permit probability of detection (POD) performance, probability of false call (FCP) performance, and/or sizing performance to be evaluated at an appropriate level of confidence for the range of flaw sizes of interest (i.e., flaw sizes ranging from less than the repair criteria to sizes where the structural performance criteria would not be met).

d) Each data set for a given degradation mechanism should consist of service degraded tube specimens (i.e., specimens removed from operating steam generators), to the extent practical. Data acquisition with the subject NDE technique should take place prior to tube removal. Service degraded tube specimens may be supplemented as necessary by tube specimens containing flaws fabricated using mechanical or chemical methods provided it is firmly established in written documentation to be maintained as part of the supplemental performance demonstration record that signal responses are fully consistent with those in the field for the same flaw geometry. In particular, fabricated flaws should exhibit signal responses of similar voltage amplitude and signal to noise as flaws in the field with the same flaw geometry. For example, electric discharge machining (EDM) notches should not be used to represent stress corrosion cracks since EDM notches exhibit a higher voltage response than cracks with higher signal to noise.

e) NDE technique and personnel flaw detection, false call, and sizing performance for each grading unit should be evaluated against the actual flaw geometry.

f) Records of the supplemental performance demonstration should be maintained by the organization (e.g., vendor, utility) conducting the demonstration. Documentation to be included as part of the technique supplemental performance demonstration records should include a complete description of the NDE technique (data acquisition equipment and instrumentation, data acquisition procedures, and data analysis procedures), including all essential variables and the demonstrated values of these variables, the data sets used (including a description thereof), and the results of the performance demonstration.

C.1.2.2 Use of Non-Validated NDE Techniques

Non-validated NDE techniques refers to techniques that have not been validated for a given application in accordance with C.1.2.0 of these guidelines.

Non-validated techniques may be used to supplement the use of validated techniques. However, with respect to any additional indications detected by the non-validated technique (i.e., not detected by the validated technique), technical justification must be developed as a basis for not repairing the affected tubes. The technical justification, to be maintained as part of the inspection record, must demonstrate that the additional indications satisfy the applicable repair criteria.

Non-validated NDE techniques for flaw detection and/or sizing may be used for applications for which there are no available techniques which have been validated in accordance with C.1.2.0 of these guidelines, provided the techniques are qualified for detection in accordance with the EPRI guidelines, Section 7 and Appendix H. A comparative evaluation should be performed for available non-validated techniques and the best of these techniques in terms of detection and sizing performance for that degradation mechanism should be employed. This comparative evaluation should be documented as part of the inspection record. POD and sizing performance for such alternative techniques should be quantified based on available information from the field and the laboratory to assess the capabilities of these techniques to perform reliable detection and sizing of flaws associated with a given mechanism, to determine the most appropriate NDE technique for that application, and to identify needed improvements in NDE capabilities. POD performance should be assessed to ensure that the subject technique can reliably detect flaws before these flaws fail to meet the structural performance criteria of C.2.1.1 or before they may potentially leak under postulated accident conditions. The detection and sizing performance estimates should consider the potential decrement in performance if flaws of a given size in the field are exhibiting lower signal to noise than is implicit in the bulk of the available information. In the meantime, licensees should take action to develop a validated technique in accordance with C.1.2.0. This action should be taken on an expedited basis in concert with other affected utilities and/or industry organizations.

When no validated NDE technique for flaw sizing exists for a given application (flaw mechanism), all indications found which are potentially associated with that degradation mechanism should be considered to exceed the applicable plugging criteria.

NDE personnel should undergo training, written examination, and performance demonstration consistent with the guidelines of the EPRI guidelines, Section 6.2 or Appendix G, prior to the use of a non-validated NDE technique for a given application, to the extent practical. The major practicality consideration is the availability of an appropriate, statistically significant data set for performance demonstration.

For some degradation mechanisms, such as various stress corrosion cracking mechanisms, there may be no available techniques that have been validated for sizing in accordance with C.1.2.0 of these guidelines. Nevertheless, information on actual sizing performance demonstrated as part of the supplemental performance demonstration of this section can be a useful tool for facilitating the condition monitoring and operational assessments in C.3.0 and C.4.0, respectively. For example, in cases where depth sizing performance is very poor, it may be possible to demonstrate that flaws at or near 100% through-wall can reliably identified. This kind of information can be useful for performing condition monitoring and operating assessments on tube leakage integrity. Additionally, in cases where depth sizing performance is poor, it will generally be possible to quantify length sizing performance. This kind of information can be useful for performing conservative condition monitoring assessments and operational assessments for tube structural and leakage integrity. Finally, in cases of poor depth sizing performance, it may be possible to demonstrate that NDE techniques and personnel are capable of reliably sorting out a subset of indications which have a high likelihood of containing the most limiting indications from structural integrity and leakage integrity point of view. The basis for sorting could be the indicated depth or voltage response of each indication. The identified subset of tubing may then be subjected to additional monitoring actions as discussed in C.3.0, such as in-situ pressure testing, to confirm that the tube integrity performance criteria in C.2.0 are met.

C.1.3 Inspection Scope and Frequency

C.1.3.1 Preservice Inspections

The EPRI guidelines (Reference X) provide acceptable guidance for conducting preservice inspections, subject to the following clarifications.

1) Preservice inspection should be conducted over the full tube length. *(Consistent with the standard technical specification (STS).)*

2) This inspection should be performed after the field hydrostatic test and prior to initial power operation. *(Consistent with STS.)*

[Note: This approach permits a general purpose exam with bobbin. Current STS requires use of techniques and equipment expected to be used during subsequent inservice inspections.]

C.1.3.2 Frequency of Inservice Inspections

The EPRI guidelines (Reference X), Section 3.2, provide acceptable guidelines concerning the frequency of inservice inspection for each steam generator subject to the additional guidance of this section below *[and subject to the resolution of staff comments concerning the EPRI guidelines]*. Inservice inspections of each steam generator should be performed at a frequency as needed such that operational assessment in accordance with C.4.0 demonstrates that tube integrity performance criteria in C.2.0 will continue to be met prior to the next scheduled inspection of that steam generator. Inservice inspections (unscheduled) should also be performed during plant shutdown subsequent to any of the following conditions:

1) primary-to-secondary leakage leading to plant shutdown for repair of the leaking tube(s); applicable only to leaks involving tube, plug, or sleeve flaws or sleeve-to-tube welds

2) seismic occurrence greater than the Operating Basis Earthquake

3) loss-of-coolant accident requiring actuation of the engineered safeguards

4) main steam line or feedwater line break

C.1.3.3 Initial Inspection Sample for Inservice Inspections

The initial inspection sample size and selection should be in accordance with the EPRI guidelines (Reference X), Section 3.3, subject to the additional guidelines of this section *[and subject to resolution of staff comments concerning the EPRI guidelines]*. The initial inspection sample should be over the full tube length (hot leg tube end to cold leg tube end) using appropriate NDE techniques and personnel as described in C.1.2.0.

The initial inspection sample in a steam generator should be supplemented to include tubes previously found to be degraded but left in service without repair. The number and identity of such tubes to be inspected should be 100% or, alternatively, as necessary to demonstrate by operational assessment in accordance with C.4.0 that the tube integrity performance criteria in C.2.0 will continue to be met prior to the next scheduled inspection of that steam generator. These supplemental inspections may be limited to a partial length of the tube containing the previously observed indication provided the subject degradation mechanism can be shown to be limited to that partial length. These supplemental inspections should use appropriate NDE techniques and personnel for the subject degradation mechanism as discussed in C.1.2..0

In general, the above guidance for initial sampling applies also for unscheduled inspections caused by primary-to-secondary leakage for the steam generator affected by the leak. However, if the degradation mechanism associated with the leak has been established to be confined to a "critical area" (per definition in C.1.3.4 below), the initial inspection sample may be limited to the defined region of the affected steam generator.

Indications found during the initial sample should be evaluated as necessary to establish the active degradation mechanisms present in the steam generators. The appearance of one or more new indications and/or indicated growth in pre-existing indications indicate active degradation mechanisms.

C.1.3.4 Expanded Inspection Sample

For each active degradation mechanism identified during initial sampling, an expanded inspection sample should be performed. (For unscheduled inspections caused by primary-to-secondary leakage, an expanded inspection sample is only performed if non-leaking indications involving the subject degradation mechanism are found during the initial sample.) The expanded sample should apply to the entire tube bundle of the affected steam generator unless the degradation mechanism can be demonstrated to be confined to a "critical area" in which case the expanded inspections for the subject degradation mechanism may be confined to a "defined region" consisting of the "critical area" and a surrounding "buffer zone". A "critical area" is a three-dimensional region which can be demonstrated to bound the region where the subject degradation mechanism is active. Technical justification to support identification of a critical area should be maintained as part of the inspection record. Technical justification should either (1) address the uniqueness of essential contributing factors (for the subject degradation mechanism) to the critical area or (2) demonstrate that the indications found during initial sampling are of sufficient number and spacial distribution to provide a strong empirical basis for the critical area. The "buffer zone" should extend radially from the defined region such as to include a sufficient number of tubes to confirm that the critical area does in fact bound the region where the subject degradation mechanism is active. *[Specific guidance for defining the buffer zone should be developed and included in the EPRI guidelines such that it can be referenced in this regulatory guide. The staff suggests that this guidance state that the buffer zone extend radially from the defined region by either of the following, whichever involves the fewest tubes; (1) a minimum of five tubes beyond the critical area boundary or (2) a sufficient number of tubes such that the number of tubes in the buffer zone equals the number of tubes in the critical area.]*

The size of the expanded sample (within the tube bundle or defined region, whichever is applicable) should be 100% or, alternatively, as necessary to demonstrate by operational assessment in accordance with C.4 that the tube integrity performance criteria in C.2 will continue to be met prior to the next scheduled inspection of that steam generator. The inspection should also be expanded into any uninspected steam generators, starting with a initial sample inspection in accordance with Section C.1.3.3. However, for each active degradation mechanism, this initial sample may be initially

limited to defined regions which have been identified for the subject degradation mechanism.

The expanded inspection sample for each active degradation mechanism should be performed with appropriate NDE techniques and personnel for that mechanism as discussed in C.1.2.0. Where more sensitive and more accurate NDE techniques are being employed compared to previous inspections, additional inspections conducted with the previously used techniques may be used as a benchmark for determining flaw growth between inspections and the rate of new indications.

The inspection results for each active degradation mechanism should be evaluated to identify all defective tubes and to provide information (e.g., flaw sizes, flaw growth rates, rate of occurrence of new indications) as necessary to support the condition monitoring assessment in C.3.0 and the operational assessment in C.4.0. "Defective" tubes are tubes containing flaws (as indicated by inservice inspection) which fail to satisfy the applicable repair criteria. The applicable repair criteria are addressed in C.5.1.

C.2.0 Performance Criteria Commensurate with Adequate Tube Integrity

Condition monitoring assessments in accordance with C.3.0 and operational assessments in accordance with C.4.0 should meet the performance goals below which are commensurate with adequate tube integrity. Use of alternative performance criteria are subject to NRC review and approval.

C.2.1 Structural Performance Criteria

The structural performance criteria may be expressed deterministically or probabilistically.

C.2.1.1 Deterministic Structural Performance Criteria

All tubes shall retain margins of safety against gross failure and/or rupture of the tubing which are consistent with the safety factor margins implicit in the stress limit criteria of the ASME Code, Section III, 1989 edition and addenda through 1989, for all service level loadings. These criteria include a margin of not less than 3 against burst (rupture) under normal operating conditions and a margin determined by the stress limits in NB-3225 of Section III of the ASME Boiler and Pressure Vessel Code under postulated accidents concurrent with the safe shutdown earthquake (SSE). *[Industry has proposed different criteria which are under staff review.]*

C.2.1.2 Probabilistic Structural Performance Criteria

a) The frequency of SG tube ruptures which occur as spontaneous, initiating events under normal operating conditions should not exceed *[5X10-3]* per reactor-year.

b) The conditional probability of rupture of one or more tubes under postulated accident conditions should not exceed the following:

- 5X10-2 for 1 or more tube ruptures
- 2.5X10-2 for 2 or more tube ruptures
- 10-3 for greater than 10 tube ruptures

The above criteria apply to the total tube rupture frequency and total conditional probability of rupture associated with all degradation mechanisms affecting the faulted steam generator. Frequency and conditional probability criteria applicable to any one degradation mechanism in the faulted steam generator should not exceed 20% of the above values.

C.2.2 Operational Leakage Performance Criteria

Operational primary-to-secondary leak rate should not exceed the operational leak rate limits as discussed in Section C.8.2 and included in the technical specifications.

C.2.3 Accident Leakage Criteria

Calculated potential primary-to-secondary leak rate during limiting postulated events should:

1) not exceed the total charging pump capacity of the primary coolant system

2) be such that the offsite radiological dose consequences, evaluated in accordance with C.9.0, do not exceed 10 CFR Part 100 guidelines and radiological consequences to control room personnel are in accordance with GDC-19.

C.3.0 Condition Monitoring Assessment

The as-found condition of tubing should be monitored during each tube inspection, whether scheduled or unscheduled, to confirm that tubes meet the performance criteria of C.2.0. In addition, operational leakage should be monitored in accordance with C.8.0 to confirm that performance criterion C.2.2 is met. Should these performance criteria not be met, this should be reported to the NRC within 24 hours and corrective actions should be implemented in accordance with C.6.0 prior to plant restart.

For an unscheduled inspection due to primary-to-secondary leakage, the condition monitoring assessment need only address the degradation mechanism which caused the leak provided the interval between scheduled inspections are not lengthened. (However, it will be necessary to estimate the contribution of accident induced leakage from the other active degradation mechanisms, as determined from the most recent operational assessment for these mechanisms, to demonstrate that performance criteria for accident induced leak rate is met.)

Specific considerations relative to monitoring tube structural integrity, operational leakage integrity, and accident leakage integrity are presented in C.3.1, C.3.2, and C.3.3, respectively. Additional details concerning specific topics in these sections are addressed in C.3.4. The condition monitoring assessment is subject to the reporting criteria in D.1 and D.2.

C.3.1 Structural Integrity

Tube structural integrity may be monitored against either the deterministic criteria in C.3.1.1 or the probabilistic criteria in C.3.1.2 for each degradation mechanism.

C.3.1.1 Assessment Vis-a-Vis Deterministic Performance Criteria

Tube structural integrity may be monitored against the deterministic criteria of C.2.1.1 by analysis, based on the results of inservice NDE inspection, or by alternative means (e.g., in-situ pressure testing) for each degradation mechanism. Tube structural integrity may be demonstrated by analysis for a given degradation mechanism provided the sizing performance of the NDE technique and personnel has been quantified in accordance with validation process of C.1.2.0. The analysis approach involves demonstrating that the most limiting flaws associated with each degradation mechanism, as determined from inservice inspection, do not exceed the appropriate "structural limit" for each degradation mechanism. "Structural limit" refers to the calculated maximum allowable flaw size developed consistent with the safety factor performance criteria in C.2.1.1. The analysis should account for all significant uncertainties such that for a flaw measured by inservice NDE inspection to be at the structural limit, the flaw satisfies the performance criteria with a probability of 0.95 evaluated at 50% confidence. Alternatively, these uncertainties may be treated such that for an indication whose measured flaw size is at the "structural limit", the associated conditional probability of burst is less than 10^{-4}. Conservative bounding models/assumptions should be employed to account for uncertainties not directly treated in the assessment.

Potential significant sources of uncertainty include NDE flaw size measurement error/variability, material property variability, and structural modeling uncertainties. Considerations for assessing NDE flaw size measurement error/variability is addressed in C.4.3.5. Structural models (i.e., models relating burst pressure to a flaw size parameter(s) or to an NDE indicated flaw size parameter(s)) may be empirical or analytical (i.e., idealized models based on engineering mechanics). Empirical models should be in accordance with C.3.4.2 and should quantify significant model uncertainties such as burst pressure data scatter and the parameter uncertainty of the empirical fit. Analytical models generally do not explicitly quantify uncertainties in the model estimates and, thus, should be developed to produce bounding estimates. The conservatism of analytical models should be confirmed by test.

For certain degradation mechanisms, analytical approaches to demonstrating tube integrity may be inappropriate or inefficient due to an inability to size certain flaw dimensions, large measurement error/variability

of NDE sizing measurements, and/or large uncertainties of the structural models. These difficulties may necessitate bounding approaches to ensure a conservative analysis, but may lead to unrealistic (overly pessimistic) results. Other approaches, such as in-situ pressure testing, may provide a more realistic assessment and may be used as an alternative to, or as supplement to the above analytical approach for a given degradation mechanism to demonstrate structural integrity in accordance with the performance criteria of C.2.1.1. Guidance for in-situ pressure testing to demonstrate the performance criteria are met is provided in C.3.4.3. In addition, accumulated data from in-situ pressure testing, over time and from among different plants (using consistent NDE techniques), may be used to develop empirical structural models and, thus, may provide an enhanced basis for condition monitoring by analysis. (Such empirical models, of course, would only be applicable to tubes with burst strengths less that the maximum burst pressure achieved during in-situ pressure testing.) Such empirical models are subject to the criteria of C.3.4.2. In addition, the variability of NDE flaw size measurements should be quantified in accordance with C.4.3.5.

C.3.1.2 Assessment Vis-a-Vis Probabilistic Performance Criteria

Considerations for monitoring tube structural integrity against the probabilistic performance criteria of C.2.1.2 should include the following for a given degradation mechanism:

a) Probabilistic approach should only be used in cases where inservice inspection techniques and personnel are validated for detection and sizing in accordance with C.1.2.0.

b) Establish the as-found frequency distribution of indicated flaws as a function of the relevant NDE indicated flaw size parameter(s) (i.e., indicated flaw depth, length, and/or voltage). The as-found distribution should be adjusted to consider the percentage of tubes sampled to address the subject degradation mechanism. The uncertainty of the as-found frequency distribution is characterized by consideration of NDE flaw size measurement error/variability in accordance with C.4.3.5.

c) Establish empirical models for burst pressure and/or failure load as a function of the relevant NDE flaw response parameter. These models for burst pressure and/or failure load should account for data scatter and model parameter uncertainties and should also satisfy criteria in C.3.4.2.

d) The probability of burst calculation should account for variabilities/uncertainties in NDE flaw size measurement, material properties, and in the burst pressure/failure model with appropriate statistical rigor. Statistical sampling methods such as Monte Carlo may be used.

e) The conditional probability estimate should be an expected (mean) value.

C.3.2 Operational Leakage Integrity

Operational leakage integrity should be monitored during plant

operation in accordance with C.8.1.

C.3.3 Accident Leakage Integrity

The potential total primary-to-secondary leakage rate and the associated radiological consequences for the most limiting postulated design basis accident should be assessed, based on the "as-found" condition of the SG tubing, to confirm that the performance criteria for accident-induced leakage (Section C.2.3) were met immediately prior to the outage. This is accomplished by demonstrating that the potential accident-induced total leak rate does not exceed the normal charging pump capacity of the primary coolant system and that the associated radiological consequences, calculated in accordance with C.9.0, do not exceed 10 CFR Part 100 guidelines and are in accordance with GDC 19. The potential leak rate my be determined by analysis, based on the results of inservice NDE inspection, or by alternative measures (e.g., in-situ pressure testing). The potential leak rate may be determined by analysis for a given degradation mechanism provided the sizing performance of the NDE technique and personnel has been quantified in accordance with the validation process of C.1.2.0. The potential accident-induced total leak rate should be an upper 95% quantile estimate (one-sided) evaluated at 50% confidence, based on quantitative consideration of uncertainties affecting the estimate. Conservative bounding models/assumptions should be employed to account for uncertainties not directly treated in the assessment.

Key elements of a condition monitoring accident leakage assessment by analysis should include the following for each degradation mechanism:

1) Establish the as-found frequency distribution of indicated flaws for each active flaw mechanism as a function of the relevant NDE indicated flaw size parameter(s) (i.e., indicated flaw depth, length, and/or voltage). The distribution should be adjusted statistically to consider the percentage of tubes sampled to address the subject degradation mechanism. The uncertainty of the as-found frequency distribution is represented by the uncertainty/variability of the NDE measurements. Treatment of NDE measurement uncertainty/variability is addressed in Section C.4.3.5.

2) Establish the potential for and magnitude of leakage as a function of the relevant flaw size parameter(s) (flaw depth and/or length) or the relevant NDE indicated flaw size parameter(s) (i.e., indicated flaw depth, indicated flaw length, or voltage response) for each flaw mechanism. The potential for leakage may be characterized as the probability that a given flaw (of given size or NDE indicated size) may leak under the postulated accident conditions (i.e., probability of leakage (POL)). Magnitude of leakage may be characterized as the conditional leak rate for the given flaw, given that leakage occurs. Models for evaluating POL and conditional leak rate may be analytical (i.e., idealized models based on engineering mechanics) or empirical. Analytical models generally do not explicitly quantify

uncertainties in the model estimates and, thus, should be developed to produce bounding estimates. The conservatism of analytical models should be validated by test. Empirical models should conform to the guidance of Section C.3.4.2 and quantify significant uncertainties. Potential sources of uncertainty to be considered should include model parameter (model fit) uncertainties, uncertainties indicated by data scatter, and material property uncertainties.

3) The leakage calculation for each flaw and/or for total SG leakage rate may be performed deterministically or probabilistically (e.g., with statistical sampling methods such as Monte Carlo). The calculation should account for variabilities/uncertainties in NDE flaw size measurement error/variability, material properties, POL, and conditional leak rate model with appropriate statistical rigor.

In-situ pressure testing in accordance with the guidelines in C.3.4.3 may be used as part of, or as an alternative to condition monitoring by analysis for a given degradation mechanism. Data from in-situ pressure testing may be used to develop empirical POL and conditional leak rate models as a function of NDE indicated flaw size parameters and, thus, provide a basis for condition monitoring by analysis. Such empirical models are subject to the criteria of C.3.4.2. In addition, the variability of the measurement of the NDE flaw response parameter must be quantified in accordance with C.4.3.5. In the meantime, pending development of valid empirical models and quantification of NDE measurement variability, condition monitoring by in-situ pressure testing may be performed as an alternative to condition monitoring by analysis for a given degradation mechanism. Estimates of total leak rate from the results of the in-situ tests should assume no functional relationship between leakage and the NDE flaw response parameter, unless there is sufficient data and a rigorous statistical basis for doing so in accordance with C.3.4.2. These estimates should be adjusted to reflect indications involving the subject degradation mechanism which were not subjected to the pressure tests. In addition, these estimates should reflect the percentage of tubes sampled by NDE to address the subject degradation mechanism. Assuming a sufficient number of tubes leak during testing, the total leak rate estimate should be a bounding estimate with a probability of 0.95 evaluated at 50% confidence. Alternatively, an acceptable bounding approach for determining total leak rate is to assume that POL equals the percentage of tubes that were pressure tested that exhibited leakage and that the conditional leak rate, given leakage occurs, is equal to the maximum leak rate observed among the leaking tubes. Total leak rate may be assumed to equal zero if no leaking tubes are observed during in-situ pressure testing.

C.3.4.0 Special Considerations for Condition Monitoring Assessment

C.3.4.1 Loadings

The following types of loadings should be considered:

a) Lo‿dings associated with normal plant operation, including startup, operation in the power range, hot standby, cool down, as well as all anticipated transients (e.g., loss of

electrical load, loss of off site power) that are included in the design specifications for the plant.

b) Loadings and tube deformations imposed on the tube bundle during the most limiting postulated design basis accidents. Dynamic loading considerations should be included in the evaluation. All major hydrodynamic and flow-induced forces should be considered.

The combination of loading conditions for the postulated accident conditions should be evaluated in accordance with the licensing basis and should include, but not necessarily be limited to, consideration of the following sources:

- Pressure differentials associated with loss of secondary system pressure
- Impulse loads due to rarefaction waves during blow down
- Loads due to fluid friction from mass fluid accelerations
- Loads due to centrifugal force on u-bends caused by high velocity fluid motion
- Loads due to dynamic structural response of the steam generator components and supports
- Seismic loads
- Flow induced vibration during blow-down from main steam line break (MSLB)

C.3.4.2 Empirical Models

C.3.4.2.1 Statistical Modeling

Empirical correlations should satisfy standard statistical "goodness-of-fit" and "significance-of-correlation" criteria. Empirical models for burst pressure and conditional leak rate should explicitly account for data scatter and for model parameter (e.g., slope and intercept) uncertainties. Where "significance of correlation" cannot be rigorously demonstrated for conditional leak rate models (e.g., a linear regression fit cannot be shown to be valid at the 5% level with a "p-value" test), the regression fit of the leak rate data as a function of flaw size (or indicated flaw size) should be assumed to be a constant value. Empirical models for probability of leakage (POL) should explicitly account for model parameter uncertainty. For POL models, a number of functional forms may exhibit similar "goodness of fit" attributes; however, they may lead to significantly different results for a given flaw size. Thus, the functional form of the fit

should be selected with care such as to ensure a conservative leakage assessment.

C.3.4.2.2 Testing Issues

Laboratory systems for measuring burst pressure and leak rate should accommodate and permit measurement of as high a leak rate as may be practical, including leak rates which may be in the upper tail of the leak rate distribution for a given flaw size (e.g., length, voltage). Leak rate data should be collected at temperature for differential pressure loadings associated with the limiting postulated accident. When it is not practical to perform hot temperature leak tests, room temperature leak rate testing may be performed as an alternative. Burst testing may be performed at room temperature. Burst and leakage rate correlations and/or data should be adjusted as necessary to reflect the appropriate pressure and temperature assumptions for the postulated limiting accident.

C.3.4.2.3 Data Exclusion Issues

Empirical burst and leakage rate models should account for all data, except in the following cases:

a) Data are associated with a randomly invalid test. Note, this criteria does not apply when tests are systematically invalid for the most extreme data. For example, failure to attain the desired test pressure due to excessive specimen leakage is a "systematically" invalid test rather than "randomly" invalid test. This is because test system limitations prevent leakage measurements for specimens exhibiting relatively high leak rates. Exclusion of such data would tend to skew the correlation.

b) Data are associated with atypical morphology based on morphology criteria which are defined rigorously and applied to all data, and which can be unambiguously applied by an independent observer provided: (1) the model can be conservatively applied to flaws exhibiting the atypical morphology or (2) a separate model is developed to address flaws with the atypical morphology and NDE can reliably discriminate flaws exhibiting the atypical morphology.

c) Exclusion of data results in conservatism associated with application of the affected correlation.

Statistical tests alone do not provide an adequate basis for determining a burst or leakage test to be invalid or for deleting data from the data base.

C.3.4.3 In-situ Pressure Tests

C.3.4.3.1 Methodology

In-situ pressure testing refers to hydrostatic pressure tests performed on installed tubing in the field. The purpose of these tests is to demonstrate the subject tubes satisfy the structural and accident-induced leak rate performance criteria in C.2.0. In-situ pressure testing, including the test apparatus, instrumentation, and procedures are subject to the requirements of 10 CFR 50, Appendix B, "Quality Assurance."

A structural assessment should be performed and maintained, or cited by reference, as part of the test record for each application (i.e., flaw mechanism and location) demonstrating that the test is capable of producing a stress state at the flawed section of tubing which is equivalent to, or a conservative bound of the actual stress state during normal operation and postulated accident conditions multiplied by the appropriate factor of safety in accordance with C.2.1.1. Where the actual limiting stress state includes bending stress (e.g., from loss-of-coolant accidents (LOCA) or SSE), the corresponding test pressure should be adjusted as appropriate to reflect these stresses. The tests may be conducted at room temperature; however, the test pressures should be adjusted to account for tube material properties at the appropriate hot conditions. In addition, leak rate data should be adjusted as appropriate to reflect the actual temperature during postulated accidents. The design of the test apparatus and test pressures must also consider any potential fixidity between the tubes and tube support plates due to the buildup of corrosion products, as necessary, to ensure that the appropriate stress state is produced by the test.

Leak rate testing should be conducted at a pressure differential simulating the most limiting postulated accident, subject to test pressure adjustments as discussed below. Should it not be possible to achieve the desired pressure level due to leakage through the flaw in excess of the makeup capacity of the test system, an engineering assessment, to be maintained as part of the test record, should be performed to project the expected leak rate at the desired pressure level. This assessment should include NDE characterization of the relevant flaw dimensions to be performed subsequent to the termination of the leakage test. This assessment should also utilize an empirical leak rate versus flaw size model or an analytical model which has been validated by test. Subsequent to leak rate testing, each subject tube should be tested at a pressure corresponding to the most limiting deterministic structural criterion to demonstrate adequate structural margin. Such testing may be performed with a bladder, as necessary, to achieve the desired test pressure. Such bladders may tend to tend to increase the observed burst pressure by on the order of 5 to 10% (Reference X), depending on bladder design and material, and this also needs to be accounted for when determining the appropriate test pressure.

C.3.4.3.2 Tube Selection

[Guidelines for number and selection of tubes for hydrostatic pressure testing are under development by the industry. The staff will review these guidelines for possible endorsement by this regulatory guide. Alternatively, the staff will develop appropriate guidance.]

C.4.0 Operational Assessment

An operational assessment should be performed to demonstrate that the performance criteria of C.2.0 will continue to be met until the next scheduled steam generator inservice inspection. The length of the operating cycle prior to the next scheduled inspection and the tube repair criteria should be adjusted as necessary to meet this objective. Additional corrective actions in accordance with C.6.0 should also be performed as necessary to meet this objective. The operational assessment and implementation of the resulting corrective actions should be fully completed within 90 days following plant restart from an inspection outage. However, it will generally be necessary to perform at least a preliminary assessment prior to performing tube plugging and/or repairs to ensure that the repair criteria being implemented are sufficient to support operation for the planned operating interval preceding the next scheduled steam generator inspection.

For an unscheduled inspection due to primary-to-secondary leakage, the operational assessment need only address the degradation mechanism which caused the leak provided the scheduled interval between scheduled inspections remains unchanged and provided the leakage was not due to a factor that would affect prior operational assessments performed for the other degradation mechanisms.

Specific considerations for performing an operational assessment of tube structural integrity and accident leakage integrity are provided in C.4.1 and C.4.2, respectively. The performance criteria in C.2.2 for operational leakage integrity does not apply to the operational assessment of this section. Additional details concerning specific topics in these sections are addressed in C.4.3.

C.4.1 Structural Integrity

C.4.1.1 Assessment Vis-a-Vis Deterministic Performance Criteria

Reasonable assurance that tube structural integrity will continue to be adequately maintained is established by demonstrating that the projected condition of the most limiting tubes immediately prior to the next scheduled inspection satisfies the deterministic criteria of C.2.1.1 for each degradation mechanism. Conceptually, this involves demonstrating that the projected limiting flaw sizes do not exceed the appropriate "structural limit" (previously defined in C.3.1.1) for each degradation mechanism. Equivalently, this can involve demonstrating that the projected limiting flaws for each degradation mechanism will exhibit failure load capacities consistent with the criteria of C.2.1.1. The assessment methodology should account for all significant uncertainties such that should the most limiting projected flaw size be at the calculated structural limit immediately prior to the next scheduled inspection, the most limiting actual flaw satisfies the performance criteria with a probability of 0.95 evaluated at 95% confidence. The assessment methodology may performed deterministically or probabilistically (e.g., with statistical sampling methods such as Monte Carlo). Alternatively, these uncertainties may be treated such that should the most limiting projected flaw size be at the calculated structural limit, the most limiting

actual flaw has a conditional probability of burst of less than 10^{-4} during the limiting postulated accident. Conservative bounding models/assumptions should be employed to account for uncertainties not directly treated in the assessment.

Potential significant sources of uncertainty include uncertainties associated with the projected limiting flaw size, material property variability, and structural model uncertainties. General considerations for projecting the most limiting flaw sizes associated with each degradation mechanism, including potential significant sources of uncertainty/variability, include the following:

a) the frequency distribution of detected indications left in service as a function of NDE indicated flaw size

b) the frequency distribution of detected indications in each previous inspection as a function of NDE indicated flaw size for tubes which have not been repaired or plugged and were not inspected during the current inspection

c) the frequency distribution of flaw growth rates determined in accordance with C.4.3.3

d) the rate and size distribution function of new indications as a function of time between inspections in accordance with C.4.3.4

e) the distribution of NDE sizing error/variability determined in accordance with C.4.3.5

f) the level of sampling performed during the current inspection and date of last inspection for uninspected tubes

Note the above considerations for projecting the limiting flaw size are based on the premise that the flaw sizing performance of the NDE technique and personnel has been quantified in accordance with validation process in C.1.2.0 for the subject degradation mechanism. Where this is not the case, alternative and/or bounding approaches must be taken as discussed later in this Section.

Specific details for projecting the maximum flaw size are to be developed by licensees. The performance of the predictive methodology in projecting the maximum flaw size should be evaluated based on the results of future inservice inspections and appropriate adjustments made to the methodology as necessary to ensure this objective is met.

Structural models (i.e., models relating burst pressure to a flaw size parameter(s) or to an NDE flaw parameter(s)) may be empirical or analytical (i.e., idealized models based on engineering mechanics). Empirical models should be in accordance with C.3.4.2 and should quantify significant model uncertainties such as burst pressure data scatter and the parameter

uncertainty of the empirical fit. Analytical models generally do not explicitly quantify uncertainties in the model estimates and, thus, should be developed to produce bounding estimates. The conservatism of analytical models should be confirmed by test.

For certain degradation mechanisms, operational assessment methodologies may be inefficient due to an inability to size certain flaw dimensions, large measurement error/variability of NDE sizing measurements, and/or large uncertainties of the structural models. These difficulties may necessitate bounding approaches to ensure a conservative analysis. Appropriate benchmarking of the assessment against the results of in-situ pressure tests performed during condition monitoring provide a potential means for mitigating excessive conservatism. However, the development of NDE techniques with good POD and sizing performance and more precise structural models is key to ensuring a realistic operational assessment and avoiding unnecessary corrective actions (including operational restrictions).

C.4.1.2 Assessment Vis-a-Vis Probabilistic Performance Criteria

Considerations for performing the operational assessment against the probabilistic performance criteria of C.2.1.2 for structural integrity should include the following for a given degradation mechanism:

a) Probabilistic approach should only be used in cases where inservice inspection techniques and personnel are validated for detection and sizing in accordance with C.1.2.0.

b) Calculate the frequency distribution of flaws by size projected to exist immediately prior to next scheduled inspection based on the considerations identified in C.4.1.2. Specific details for projecting the distribution of flaw sizes are to be developed by licensees. The performance of the predictive methodology in projecting a distribution which results in a conservative estimate of conditional probability of rupture should be evaluated based on the results of future inservice inspections and appropriate adjustments made to the methodology as necessary to ensure this objective is met.

c) Establish empirical burst pressure and/or failure load as a function of the relevant NDE flaw response parameter. These empirical models should account for data scatter and model parameter uncertainties and are subject to the special considerations in C.3.4.

d) The projected distribution of flaw sizes and conditional probability calculation should include a rigorous statistical treatment of all significant sources of uncertainty/variability affecting the calculation including growth rate, NDE sizing measurement, and burst pressure/failure model. Statistical sampling methods such as Monte Carlo may be used.

e) The conditional probability of rupture should be evaluated at the one sided, upper 95% confidence level.

b. Accident Leakage Integrity

The potential total SG primary-to-secondary leak rate and the associated radiological consequences during the most limiting postulated design basis accident should be assessed relative to the performance criteria for accident-induced leakage integrity in C.2.3, based on the frequency distribution of flaw indications as a function of NDE indicated flaw size projected to occur immediately prior to the next scheduled SG inspection outage. This may be accomplished by demonstrating that the potential accident-induced total leak rate does not exceed the normal charging pump capacity of the primary coolant system and that the associated radiological consequences, calculated in accordance with C.9.0, do not exceed 10 CFR Part 100 guidelines and are in accordance with GDC 19. The potential accident-induced total leak rate should be an upper 95% quantile estimate (one-sided) evaluated at 95% confidence, based on quantitative consideration of uncertainties affecting the estimate. Conservative bounding models/assumptions should be employed to account for uncertainties not directly treated in the assessment.

Conservative bounding models/assumptions should be employed to account for uncertainties not directly treated in the assessment.

General considerations for projecting the flaw size frequency distribution for each degradation mechanism as a function of NDE indicated flaw size, including potential significant sources of uncertainty/variability, are the same as those identified in C.4.1.1 for projecting the most limiting flaw sizes. Considerations for establishing the potential for and magnitude of leakage for each degradation mechanism as a function of flaw size or NDE indicated flaw size are the same as those identified in C.3.3.

For certain degradation mechanisms, operational assessment methodologies may be inefficient due to an inability to size certain flaw dimensions, large measurement error/variability of NDE sizing measurements, and/or large uncertainties of the structural models. These difficulties may necessitate bounding approaches to ensure a conservative analysis. Appropriate benchmarking of the assessment against the results of in-situ pressure tests performed during condition monitoring provide a potential means for mitigating excessive conservatism. However, the development of NDE techniques with good POD and sizing performance and more precise structural models is key to ensuring a realistic operational assessment and avoiding unnecessary corrective actions (including operational restrictions).

C.4.3 Special Considerations for Operational Assessment

C.4.3.1 Loadings

See C.3.4.1

C.4.3.2 Empirical Models

See C.3.4.2

C.4.3.2 Flaw Growth Rates

Flaw growth rates over the next inspection interval must be estimated for each degradation mechanism for purposes of projecting flaw size or flaw size distributions expected to exist prior to the next scheduled inspection. These projected flaw sizes or flaw size distributions are used as part of operational assessments performed in accordance with C.4.0. Where possible, these growth rate estimates should be based on the inservice inspection results from the most recent inspection and the previous one or two inspections. The inservice inspection results may be used where the NDE techniques and personnel used to obtain these results were validated for sizing in accordance with C.1.2.0. When non-validated techniques and personnel have been employed, the inspection results may still be used for purposes of assessing growth rates provided it has been demonstrated during the validation process that there is a statistically valid correlation between the actual flaw size or burst strength and the NDE measured flaw size. Where the NDE technique does not satisfy these provisions, indications found during a given inspection will generally be "new indications" since indications found in previous inspections will have been plugged or repaired in accordance with C.1.2.2. Under these circumstances, the projected flaw size distribution prior to the next scheduled inspection will be determined primarily on the basis of the observed "rate and size of new indications" (see C.4.3.4) rather than on the basis of observed growth rates.

Flaw growth rates should be evaluated on the basis of the change in flaw size between inspections where there is a detectable flaw indication during both inspections (Growth implications of new indications are addressed in C.4.3.4). These growth rates should be adjusted as necessary to reflect any increase or decrease in the length of the time interval between scheduled inservice inspections. For a given indication found during the latest inspection, the previous inspection results for the subject location should be evaluated, consistent with the NDE data analysis guidelines for the degradation mechanism being evaluated. Where the data analysis guidelines employed during the previous inspection differ from those employed during the latest inspection, the previous data should be evaluated to the latest data analysis guidelines. In addition, the previous data should be adjusted to compensate for differences in data acquisition procedures to the extent there is a technical basis for doing so. When this is not possible, the locations of the indications (or a large sample of these locations) should be reinspected using the previous data acquisition procedures such that results can be compared directly to the previous inspection results. It is desirable that the same analyst be used for a given location to evaluate the data from the latest and previous inspections for purposes of assessing incremental flaw growth.

It is acceptable to supplement plant-specific growth data with applicable data from other units in cases where plant-specific data is scanty for a given degradation mechanism. The data applied from other units should be consistent with or conservative with respect to available plant-specific data regarding average and bounding growth rates. Other considerations

concerning the applicability of data from other plants include, for inside diameter degradation, similarities in Inconel microstructure, primary water chemistry, relevant design features (e.g., residual stress levels associated with tube expansions and u-bends, sleeve design), level of denting, and operating temperature. Other considerations for outer diameter corrosion include similarities in secondary water chemistry, crevice chemistry, thermal and hydraulic environment, Inconel microstructure, level of denting, and relevant design features.

It is acceptable to use a statistical model fit of the observed growth rate distribution to support operational assessments provided that the statistical model accounts for the upper tail of the observed distribution.

When statistical sampling techniques are applied to the growth rate distribution, negative growth rate samples should be treated as zero growth rate.

Probability distributions of flaw growth rates constructed directly from comparative inspection results will tend to be contaminated by NDE flaw measurement repeatability error which will tend to extend the tails of the distribution in both directions. It is conservative to ignore this contamination where the measurement error is random. Alternatively, appropriate statistical methods may be employed to separate out the contribution of measurement error. However, the deconvolved distribution attributable to measurement error should be evaluated to ensure that it is consistent and fully accounted for in what is being assumed for NDE measurement error in C.4.3.5 below.

C.4.3.4 Rate and Size of New Indications

The frequency distribution of indications as a function of indicated flaw size projected to exist prior to the next inspection consists of two groups of indications. The first group consists of flaws found by inservice inspection that were permitted to remain in service prior to plant restart and which have subsequently undergone flaw growth. Thus, the projected frequency distribution of indications associated with this first group can be determined from the known distribution of indications left in service and the known distribution of flaw growth rates (see C.4.c.(3)). The second group consists of indications that were not detected by inservice inspection prior to plant restart. The indications were not detected previously because either (1) flaws were present but not detected by inservice inspection, or (2) flaws did not initiate until after plant restart. Failure of inservice inspection to detect flaws that were present can be due either to the fact that (1) the subject tube was not inspected at the flaw location or that (2) the tube was inspected, but the flaw was not detected due to NDE technique or personnel limitations. Methodologies should be developed for each degradation mechanism for projecting the frequency distribution of indications associated with the second group of indications (i.e., indications not detected during previous inspections). Predictions using these methodologies should be assessed versus the actual distribution of new indications found at the next inspection. These methodologies should be revised as necessary, based on the results of the comparative assessment.

The projected rate and size distribution of new indications may be determined, in part, on the basis of the inservice inspection results. This is contingent in the case of the size distribution on the NDE technique satisfying the same provisions as identified in C.4.3.3 for determining flaw growth rate. The projected rate of new indications should account for the anticipated rate of increase in the rate of new indications over time based on plant-specific and applicable industry experience. The previously observed size distribution of new indications may be fitted with a statistical model which conservatively accounts for the upper tail of the distribution such that the distribution may be scaled to reflect the expected number of new indications.

In cases where the NDE technique does not satisfy the provisions in C.4.3.3, alternative approaches may be taken for purposes of projecting the most limiting sizes of new indications for purposes of supporting a conservative or bounding operational assessment. For example, burst test results of in-situ pressure tests performed as part of condition monitoring may be used to estimate flaw sizes equivalent to the observed burst pressures or to conservatively bound the flaw sizes based on the maximum test pressures achieved where no burst was observed. The projected bounding values of flaw size should be adjusted as appropriate to reflect the projected increase in rate of new indications (which would tend to stretch the upper tail of the size distribution to higher values) and to account for increases or decreases in the length of the time interval between scheduled inservice inspections.

5) NDE Sizing Error

The probability distribution of NDE measurement error may be determined from the performance demonstration data for NDE techniques and personnel obtained during the validation process for sizing in accordance with C.1.2.0 and C.1.2.1. Consideration should be given to whether personnel measurement uncertainty can be reduced with the practice of reviewing field data with independent analysts. Whether this can in fact lead to a reduction in measurement uncertainty would need to be demonstrated for each application (i.e., for each set of degradation mechanisms, NDE technique, data analysis procedures, and procedures relating to how the independent analyses are performed and discrepancies resolved.

C.5.0 Tube Plugging and Repairs

All tubes found to be defective during preservice or inservice inspection should be removed from service by plugging or repaired prior to plant startup. Tubes are defective when they contain flaws which fail to satisfy the applicable tube repair criteria for the subject degradation mechanism. Guidelines for the development of tube repair criteria are given in C.5.1 below. Guidelines concerning the development of plugging and repair methodologies are given in C.5.2 below.

C.5.1 Tube Repair Criteria

The purpose of tube repair limits, in conjunction with the other

programmatic elements of this regulatory guide, is to provide reasonable assurance that tubes accepted for continued service without repair will exhibit adequate tube structural and leakage integrity, consistent with the performance criteria of C.2, with appropriate allowance for NDE measurement error and for flaw growth prior to the next scheduled inspection.

The tube repair criteria for each active degradation mechanism should be 40% of the nominal tube wall thickness, subject to demonstrating by operational assessment in accordance with C.4 that the tube integrity performance criteria in C.2 will continue to be met prior to the next scheduled inspection of that steam generator. This 40% criterion is applicable to the maximum measured depth of the subject indication. *[Industry has proposed that the 40% criterion be applicable to the measured average depth of the subject indication. This proposal requires further development and justification before it can be accepted by NRC.]*

Alternative repair criteria (ARC) may be developed and implemented for specific degradation mechanisms as part of a steam generator degradation specific management (SGDSM) strategy. SGDSM constitutes an integrated approach consisting of an operational assessment methodology in accordance with C.4, specific inservice inspection programs (with specified frequency and level of sampling, specified qualified/validated NDE techniques) consistent with C.1, and repair limit computational methods aimed at ensuring that the performance criteria for tube integrity in C.2 are met prior to the next scheduled inspection. The ARC associated with an SGDSM strategy may not be a fixed value, but may involve a computational method to be implemented as part of the operational assessment for determining an acceptable ARC value which is consistent with ensuring that the performance criteria for tube integrity are met prior to the next scheduled inspection. SGDSM strategies and their technical bases should be documented in a technical report that is referenced in the plant procedures as the methodology for implementing the associated ARC.

C.5.2 Tube Plugging and Repair Methods

Plugging and repair methods should be developed, qualified, and implemented in accordance with the applicable provisions of the ASME Code and 10 CFR 50, Appendices A and B. These methods should be designed to ensure tube structural and leakage integrity, and should be qualified by both analytical and experimental programs. Repair methods may include leak limiting repair methods; however any potential leakage from these repairs during operational transients or postulated accidents should be included as part of the operability assessment of C.4. Plugs and repaired portions of tubing should be inspectable with appropriate NDE techniques and personnel as described in C.1.b. *[EPRI is developing guidelines for developing and implementing sleeving repairs. The staff will review these EPRI guidelines when and if they become available and consider whether these guidelines should be referenced or endorsed as part of this regulatory guide.]*

C.6.0 Corrective Actions

Failure of condition monitoring to confirm that the performance criteria have been satisfied should lead to the following actions prior to plant restart from the inspection outage:

a) assessment of causal factors such as, for example:

- new or unexpected degradation mechanism
- insufficient sample sizes for tube inspection
- unexpectedly high crack growth rates
- performance of NDE techniques and/or personnel is less tha expected
- deficiencies in predictive methodology for condition maintenance assessment (e.g., inadequate treatment of uncertainties)

b) implementation of corrective actions, for example:

- shortened inspection interval
- water chemistry enhancements
- chemical cleaning
- reduce hot leg temperature
- design modifications
- larger tube inspection samples
- improved inspection techniques (to enhance POD and sizing performance)
- enhanced trair ing of NDE personnel
- more restrictive tube repair (plugging) criteria
- enhanced monitoring of operational leakage
- reduced coolant iodine activity limits
- enhancements to predictive methodology for operational assessment

Note, the adequacy of these corrective actions to provide reasonable assurance that tube structural and leakage integrity will be maintained prior to the next scheduled inspection should be confirmed as part of the operational assessment in accordance with C.4.0. A reduction in the length of operating time between inspections should be made if it cannot be shown with a

high degree of confidence that other corrective actions are sufficient to ensure that the performance criteria in C.2 will be met for the period extending to the next scheduled inspection.

Irrespective of whether the condition monitoring assessment confirms that the tubes meet the performance criteria of C.2.0, actions should be taken as necessary such that the operational assessment confirms that the performance criteria will be satisfied throughout the operating cycle prior to the next scheduled inspection.

C.7.0 Preventive Measures

Preventive measures should be developed and implemented to minimize the potential for tube degradation and to mitigate active degradation mechanisms in accordance with the guidelines given below. The effectiveness of these preventive measures, as indicated by inservice inspection results and other pertinent indicators, should be assessed as part of the periodic operational and condition monitoring assessments discussed in Sections C.3 and C.4, respectively.

C.7.1 Secondary Water Chemistry Program

Licensees should have a program for monitoring and control of secondary water chemistry to inhibit secondary side corrosion induced degradation. This program should include:

1) identification of all critical variables,
2) identification of a sampling schedule for the critical variables and control points for these variables,
3) identification of the procedures used to measure the values of the critical variables,
4) identification of process sampling points, which should include monitoring the discharge of the condensate pumps for evidence of condenser in-leakage,
5) procedures for the recording and management of data,
6) procedures for defining corrective actions for all off-control point chemistry conditions, and
7) a procedure identifying (a) the authority responsible for the interpretation of the data, and (b) the sequence and timing of administrative actions required to initiate corrective action.

Development of the specifics of this program is the responsibility of the licensee. However, licensees should consider the recommendations in Reference 1 when developing and/or updating their programs.

C.7.2 Loose Parts and Foreign Objects

Licensees should have a program for monitoring and control of loose parts and foreign objects to inhibit fretting and wear degradation of the tubing as follows:

C.7.2.1 Secondary Side Visual Inspections

The program should include secondary side visual inspections. The program should define when such inspections are to be performed, the scope of inspection, and the inspection procedures and methodology to be utilized. Loose parts or foreign objects which are found should be removed from the steam generators, unless it is shown by evaluation (to be maintained as part of the inspection record) that these objects pose no potential for damaging the SG tubing or any other part of the secondary system. Tubes found to have visible damage should be inspected non-destructively and plugged or repaired if the tube repair criteria developed under Section C.5 of this guide are not satisfied.

C.7.2.2 Control of Loose Parts and Foreign Objects

The program should include procedures effective in precluding the introduction of loose parts or foreign objects into either the primary or secondary side of the steam generator whenever it is opened (e.g., for inspections, maintenance, repairs, and modifications). Such procedures should include (1) detailed accountability procedures for all tools and equipment used during an operation, (2) appropriate controls on foreign objects such as eyeglasses and film badges, (3) cleanliness requirements, and (4) accountability procedures for components and parts removed from the internals of major components (e.g., reassembly of cut and removed components).

C.7.3 Measures to Mitigate Active Degradation Mechanisms

Licensees should consider developing and implementing, at their discretion, additional measures as necessary to mitigate active degradation mechanisms. Examples of such measures include providing for improved condenser integrity, minimizing air in-leakage into the secondary system, elimination of copper bearing alloys from the feed train, chemical cleaning, boric acid treatments, and operating with a reduced hot leg temperature.

C.8.0 Operational Primary-to-Secondary Leakage Monitoring/Limits

C.8.1.0 Leakage Monitoring

Primary-to-secondary leakage monitoring is an important defense-in-depth measure which can assist plant operators in monitoring overall tube integrity during operation. Monitoring also gives operators information needed to safely respond to situations in which tube integrity becomes impaired and significant leakage or tube failure occurs.

Objectives: (1) Provide clear, accurate, and timely information indicating loss of tube leakage integrity to allow remedial actions to be taken to prevent tube rupture. (2) Provide clear, accurate, and timely

information to facilitate the mitigation of any tube failure event.

Although leak-before-break cannot be totally relied upon for steam generator tubes, primary-to-secondary leakage monitoring can afford early detection and response to rapidly increasing leakage, thereby serving as an effective means for minimizing the incidence of steam generator tube ruptures. This can be achieved by having near real-time leakage information available to control room operators. Use of such monitoring capability, along with appropriate alarm set points and corresponding action levels, can help operators respond appropriately to a developing situation in a timely manner.

The monitoring program should account for plant design, steam generator tube degradation, and previous leakage experience. Degradation and leakage experience should not be limited to a specific plant. A primary measure of program effectiveness rests with the ability of operators to appropriately deal with the full range of primary-to-secondary tube leakage. The program should ensure that operators have the information and guidance needed to safely and appropriately respond to situations ranging from stable leakage at very low levels, to rapidly increasing leakage leading to or resulting from tube failure. Program elements which the staff believes will contribute to meeting the stated leakage monitoring objectives are discussed below. These elements have been shown to be important based on corrective actions taken following tube leakage or rupture events.

C.8.1.1 Monitoring Strategy

Each monitoring method has limitations, therefore, no single means of detecting primary-to-secondary leakage, nor a single monitored pathway or radionuclide should be relied upon. A monitoring strategy should use an array of methods to detect and measure leakage, and indications should be available to control room operators. Continuous control room display of key radiation monitor trends (e.g., blowdown, condenser exhaust, N-16 monitor leakage rates and change in leak rate over time) gives operators real-time information which can be used to safely respond to the full range of primary-to-secondary leakage.

Although no single monitor should be expected to fulfill all monitoring roles, some monitoring methods have demonstrated particular value in certain situations. Use of Nitrogen-16 monitors installed on or near steam lines has become increasingly common in the industry as a supplemental means of monitoring leakage. These monitors exhibit short time response to changes in leak rate and are very useful to operators, provided their limitations are understood. Indications from these monitors can greatly aid operator ability to diagnose and combat a quickly escalating primary-to-secondary leakage situation. However, the short halflife for N-16 presents some problems in the ability of the detector to measure leak rate. Changes in power level, and characteristics of the leak itself (location and type of leak) will affect the N-16 concentration reaching the detector.

Licensees should evaluate the monitoring methods available based on factors such as those given in guidance provided by EPRI Report TR-104788, "PWR Primary-to-Secondary Leak Guidelines," May 1995. Detection

capability and measurement uncertainties are discussed in the guidance, as well as the characteristics of certain monitoring methods. This is a useful basis upon which a licensee can determine the adequacy of specific parts of their monitoring system and the effectiveness of the combination of methods used.

The monitoring program should also include provisions for detection of primary-to-secondary leakage during low power or plant shutdown conditions. Licensees should ensure that means are available to detect tube leakage whenever primary pressure is greater than secondary system pressure. This includes hot shutdown conditions and plant startup situations, when normal means of detecting leakage might be limited or unavailable. For instance, the radionuclide mix is altered following a period of plant shutdown so that condenser off gas monitor indications may be questionable during startup since they are calibrated for a specific radionuclide mix based on power operation. Also, N-16 monitoring is not considered reliable at low power since lower levels of N-16 are available to trigger detector response during a tube leak.

Shutdown or low power monitoring methods do not need to be relied upon to track low levels of leakage over extended periods as might be required for power operation. Plants spend a relatively small fraction of time in low power or hot shutdown. However, it is prudent to have techniques and procedures available to detect a rapidly developing leak under these circumstances. In the event a tube failure develops, operators should have reasonable time to respond to the situation before the plant reaches full power operation, when the consequences of a tube failure would be magnified.

Monitoring instrumentation alarms and operator action levels should be selected to ensure that operators can respond to leakage in a timely fashion, prior to developing serious tube failures. Refer to Section C.8.b of this Regulatory Guide for specific guidance.

C.8.1.2 Operational Guidance

Clear guidelines should be available to direct operator response to leakage in order to minimize the chance for operator errors during a developing leak event. The EPRI Guidelines recommend operating actions in response to a range of primary-to-secondary leakage, methods of calculating leak rates from various secondary system sample points, and various strategies to track leakage once detected. The Action Levels given in the Guidelines provide a framework that licensees can use to formulate pre-planned operator actions based on specified leakage indications.

Licensees should be careful, however, not to return too quickly to a more routine monitoring regime following an increase in leakage. The Guidelines give a definition of stable leak rate ($\leq$10% increase in an hour), but confirmation of indications of slowing leak rate is not discussed. A firm basis, in terms of change in leak rate over time, upon which to determine the stability of the leak is difficult to formulate. Therefore, prudence dictates that operators should use more than a single indication as the basis for concluding that leak rates have stabilized. A similar approach, of confirming

leak rates prior to declaring a leakage condition, is applied to Action Level 2 (i.e., leak rate requiring plant shutdown) in the Guidelines.

C.8.1.3 Operator Training

Training scenarios should include various types of leakage progressions based on actual leakage events, as much as practicable. The characteristics of specific plant monitoring instrumentation should be considered when providing operator indications for training purposes.

The EPRI Guidelines offer some assistance to licensees in formulating appropriate simulator scenarios. However, licensees should ensure that information gained throughout the industry by operation with primary-to-secondary leakage or from tube failure events is used in training programs. Further, operator training should accurately reflect the expected indications and plant responses for the particular plant during a progressing tube leak that may develop into tube rupture. Various plant conditions and failures of various key indicators should be considered when devising training scenarios.

C.8.1.4 Program Updates and Self-assessment

Means should be established for the leakage monitoring program to take advantage of new data. Information from actual leakage events can be used to check the adequacy of the monitoring program or enhance its effectiveness.

The foregoing leakage monitoring program components can afford a sufficient level of defense-in-depth against primary-to-secondary leakage. However, data from actual leakage events throughout the industry can serve as a valuable tool to help licensees verify that an appropriate balance exists among the program components. For example, licensees have incorporated leakage data from previous events to adjust alert and alarm set points of radiation monitors, improve chemistry sampling procedures, and supplement primary-to-secondary training scenarios.

Licensees should also have measures in place to allow careful evaluation of leakage monitoring program performance following any primary-to-secondary leakage event at their plant. Suitable adjustments in the monitoring program can then be made based on the results of such an evaluation.

C.8.2 Operational Leakage Limits

1) Operational limits should be established for the allowable leak rate and the allowable rate of increase in leak rate from any one steam generator, beyond which prompt and controlled shutdown is initiated. These limits, when used in conjunction with a leak rate monitoring program in accordance with C.8.1, are intended to ensure that appropriate and timely action will be taken to avert rupture of a leaking tube, including tubes undergoing rapidly increasing leak rates. The Action Levels 1 and 2 criteria and Recommended Actions in the EPRI Primary-to-Secondary Leak Guidelines, Reference X, provide an acceptable approach with the exception that the >150

gallons per day (gpd) criterion in these Action Levels should be an appropriate value less than 150 gpd. An appropriate value is one which is consistent with the performance criteria in C.2.2; namely, operational leakage should not exceed 150 gpd.

2) Operational limits should be established for the allowable total leakage from all steam generators and included as part of the technical specifications if the allowable total leakage is less than 150 gpd times the number of steam generators at the plant. Operational limits on total primary-to-secondary leakage from all steam generators are not necessary if the allowable total leakage is greater than 150 gpd times the number of steam generators. These limits are to ensure that tubes initially leaking during normal service do not contribute excessively to total leakage during postulated accident conditions. Total leakage during postulated accidents stems from two sources; (1) leakage from flaws which were initially leaking prior to the event and (2) flaws that were not leaking prior to the event, but which leak during the event. Projected total leakage during postulated accidents must be demonstrated as part of the operational assessment in C.4 to satisfy the performance criteria in C.2.3, assuming the preexisting total leakage (prior to the event) was at the most limiting operational limit.

C.9.0 Radiological Assessment

Doses are calculated for two purposes. The first purpose is to demonstrate that the accident leakage performance criterion can be met. The second purpose is to ensure that technical specifications for the maximum instantaneous dose equivalent ^{131}I, the 48 hour value of dose equivalent ^{131}I, the normal operating primary to secondary leakage and the event induced primary to secondary leakage are within a range such that the accident leakage performance criterion is met.

The accident leakage performance criterion requires that the consequences of a postulated accident meet two conditions. The first is that offsite exposure to members of the public must not result in doses which exceed some fraction of or the full Part 100 guidelines depending upon the accident and the scenario. Doses should be calculated for individuals located at the Exclusion Area Boundary (EAB) and the Low Population Zone (LPZ). The second condition is that control room operator doses must not exceed the radiation dose guideline of GDC 19 of Appendix A to 10 CFR Part 50. The control room dose guidelines are defined more extensively in Standard Review Plan (SRP) Section 6.4, Control Room Habitability System.

In demonstrating that the accident leakage performance criterion can be met, doses should be calculated for any accidents involving degradation of the SG tubes. Two accidents typically evaluated include a steam generator tube rupture (SGTR) and a main steam line break (MSLB). However, there may exist other accidents where the presence of degraded tubes may exasperate the consequences of an accident. Where those conditions exist, those accidents must also be evaluated. Application of this rule may permit licensees to leave degraded tubes in service without subjecting the tubes to repairs such as plugging or sleeving. In such cases, licensees must assess whether allowing such tubes in service can result in a new or different accident from

those which were previously analyzed. In addition, a determination must be made as to whether previously analyzed accidents can have additional consequences or different consequences as a result of the degraded tubes remaining in service.

Two examples where allowing degraded tubes to remain in service may increase the consequences of a previously analyzed accident, are provided. The first example involves the application of interim plugging criteria (IPC) while the second example involves a loss of coolant accident (LOCA) analysis. In licensee evaluations of MSLB accidents, the dose assessments have been typically limited to the consideration of the normal operating primary to secondary leakage value utilized in technical specifications. Application of IPC has necessitated that both the licensee and the NRC modify the manner in which they perform MSLB analyses. IPC allows licensees to forego plugging or sleeving tubes as long as the dose guidelines of Part 100 and GDC 19 can be met. However, in allowing tubes to remain in service without being sleeved or plugged, there exists a certain risk that these tubes are potentially susceptible to additional leakage when they are exposed to a significant differential pressure (Δp). Such a significant Δp could occur as a result of a MSLB with a coincident loss of offsite power. If the degraded tubes in the SG in the steam line which has experienced the break encounter a Δp of sufficient magnitude that it causes the cracks in the degraded tubes to expand, there is an increase in the primary to secondary leakage to a rate which is higher than that during normal operation. This additional leakage is referred to as event induced leakage. Any accident analysis must account for event induced leakage in the determination of the dose consequences.

The second case involves a LOCA assessment. A licensee identified a pathway whereby degraded steam generator tubes could be a source of containment leakage in the event of a LOCA. The licensee's procedures has post LOCA long-term cooling being accomplished by the release of steam from the steam generators through either the atmospheric dump valves (ADVs) or the turbine bypass valves (TBDs). Use of either the ADVs or the TBDs following a LOCA could result in the secondary side pressure being lower than primary side pressure. Consequently, a flow path can exist from the primary side, which is open to containment following a large break LOCA, through the degraded steam generator tubes which had previously exhibited primary to secondary leakage, to the environment.

Any dose assessment must confirm that technical specifications for reactor coolant system (RCS) dose equivalent ^{131}I, normal operating primary to secondary leakage and event induced primary to secondary leakage remain applicable. This confirmation occurs when the technical specification values are substituted into the analysis. If substitution of these values causes the dose guidelines of GDC 19 or Part 100 to be exceeded, then the technical specification values must be altered to ensure that the guidelines are met.

It must be emphasized that whenever a process, such as IPC, allows degraded tubes to remain in service, an assessment must be made as to whether the consequences of any accident are exasperated because of the process and whether application of the process results in a new or different accident. When new accidents are identified or when the consequences of previously

analyzed accidents are changed because the degraded tubes are allowed to remain in service, these new accidents or the new consequences change the facility's design basis. The new accidents and the new consequences must be sent to the NRC for review and approval and may necessitate technical specification changes. Following NRC acceptance and approval, the description of the new accident and its consequences must be incorporated into the licensee's updated final safety analysis report (UFSAR).

Based upon the dose criteria presented in Table C.9-1, one accident scenario will limiting in the determination of allowable leakage. This case should be utilized in the calculation of doses for the condition monitoring case and for the operational assessment case and in the establishment of the plant specific technical specifications. This case will likely remain the most limiting case until either the scenario or the conditions, associated with the scenario, change. When a new scenario is identified as being the limiting case, if this scenario does not fall into one of the categories of presented in Table C.9-1, then a submittal is required to the NRC which identifies the accident, provides an assessment of the consequences of the accident, identifies the technical specification changes which are required as a result of the assessment and proposes a limiting dose criteria for the accident.

C.9.1 Dose Calculation Methodology

In demonstrating that the accident leakage performance criterion is met, licensees may select from either one of two methodologies for calculating the doses from SG tube degradation events. Both methodologies are deterministic in nature. The first method is referred to as the default or SRP approach. This methodology utilizes the concepts presented in Standard Review Plan (SRP) Sections 15.1.5, Steam System Piping Failures Inside and Outside of Containment (PWR), and 15.6.3, Radiological Consequences of Steam Generator Tube Failure (PWR), for calculating the doses resulting from a MSLB and a SGTR, respectively. The second methodology is referred to as the flex methodology. This methodology allows licensees to establish a plot of maximum allowable primary to secondary leak rate as a function of the maximum instantaneous RCS activity level of dose equivalent ^{131}I and the 48 hour value of dose equivalent ^{131}I. These plots are based upon the limiting accident scenario. Based upon the projected event induced primary to secondary leakage for the next operating cycle, licensees may choose to limit the maximum allowable leak rate as a function of the maximum instantaneous RCS activity level of dose equivalent ^{131}I and the 48 hour value of dose equivalent ^{131}I so that the accident leakage performance criterion can be met.

C.9.1.1 Default Methodology

This methodology is applicable to those licensees who have steam generators which have not degraded to a degree that alternate tube repair criteria has been applied, therefore, event induced leakage is not a consideration. This methodology is intended to allow licensees to incorporate their existing licensing basis as their dose assessment record to meet the accident leakage performance criterion. Usually this means incorporation of dose calculations which utilized the methodology presented in SRP Sections 15.1.5 and 15.6.3.

Most licensees will have demonstrated by these calculations that both GDC 19 and Part 100 dose guidelines have been met. In addition, most calculations will have confirmed that the technical specification values for normal operating leakage, maximum allowed instantaneous RCS activity level of dose equivalent ^{131}I and the 48 hour RCS activity level of dose equivalent ^{131}I are sufficient to ensure that a SGTR or a MSLB accident would not result in doses which would exceed either the GDC 19 or Part 100 dose guidelines or the fraction of Part 100 dose guidelines as described in the SRP Sections 15.1.5 and 15.6.3.

For most licensees, adoption of this methodology should not necessitate new or different calculations. However, for a certain vintage of reactors, the NRC did not reference any dose assessments in the Safety Evaluation Report (SER) for the reactor. Instead, the reactors were given technical specifications for the maximum instantaneous activity level of dose equivalent ^{131}I and a 48 hour value of dose equivalent ^{131}I in reactor coolant. In addition, a maximum activity level for dose equivalent ^{131}I in the secondary coolant and a maximum primary to secondary leak rate were established in technical specifications. At the time that the SER was issued it was the NRC's position that the establishment of these technical specification limits would ensure that the doses resulting from accidents involving steam generators would pose no risk to public health and safety. The staff has concluded that this position remains valid today for those reactors which have not experienced degradation of their steam generators.

The staff has identified a potential pitfall in the performance of these dose assessments. This involves calculating the doses while inconsistently applying the dose conversion factors in the calculation of dose equivalent ^{131}I and the calculation of doses. Such an inconsistent application could result in an underestimation of the dose consequence.

The activity level of dose equivalent ^{131}I is calculated using the following Equation:

$$DE\ ^{131}I = \Sigma DCF_i C_i / DCF_{131}$$

where

$DE\ ^{131}I$ = the dose equivalent concentration of ^{131}I, Ci/g;

DCF_i = the dose conversion factor for isotope i, rem/Ci;

C_i = the concentration of isotope i in the primary coolant, μCi/g;

DCF_{131} = the dose conversion factor for ^{131}I, rem/Ci.

The dose conversion factors which are to be utilized are based upon the plant specific technical specification. Typical dose conversion factors are derived from either RG 1.4, RG 1.109 and ICRP 30. Some licensees may have utilized the dose conversion factors from RG 1.109 or RG 1.4 in the calculation of the RCS curie content of dose equivalent ^{131}I but then used ICRP 30 dose factors in the calculation of doses. Based upon the predominant isotope, ^{131}I, if the

doses are calculated in this manner, then the doses will be underestimated because the amount of radioactivity which could be in the coolant is 50% less when using RG 1.4 or RG 1.109 compared to if ICRP 30 dose conversion factors were utilized. To illustrate this, the dose conversion factors for ^{131}I from RG 1.4 and RG 1.109 are 1.48 x 10^6 rem/Ci and 1.49 x 10^6 rem/Ci, respectively. This same dose conversion factor from ICRP 30 is 1.08 x 10^6 rem/Ci. Therefore, the same dose conversion factors should be utilized to calculate doses as are utilized to calculate the RCS activity level of dose equivalent ^{131}I. The staff utilizes ICRP 30.

9.2.2 Flex Methodology

In lieu of using the default methodology, the licensee may elect to utilize the dose calculation option which the staff has labeled flex. The flex methodology is applicable to licensees who have steam generators which have experienced degradation mechanisms to such an extent that an alternative repair criteria is applied to the tubes. When such a repair criteria is applied, it necessitates that licensees include in their accident assessments the contributions to doses from releases arising from event induced leakage. An example of an event induced leakage scenario was provided in the discussion on utilization of IPC and the assessment of a MSLB.

The intent of the flex methodology is to provide licensees with the operational flexibility, yet ensure that the accident leakage performance criterion continues to be met. The flex methodology is utilized to generate a plot based upon series of calculations involving a variety of allowable event induced primary to secondary leak rates which vary with the RCS activity level of dose equivalent ^{131}I. With such a plot, given the presence of a degradation mechanism, licensees are permitted to increase the event induced primary to secondary leakage while maintaining RCS activity level of dose equivalent ^{131}I below a pre-determined value. This plot would be based upon the limiting accident scenario in determining conformance with the dose guidelines of Table C.9.1-1. Whichever accident scenario resulted in the least amount of leakage would be the scenario for which the plot would be established. The plot would consist of two parts. The first would be for the maximum instantaneous value of dose equivalent ^{131}I in RCS and the second would be for the 48 hour value of dose equivalent ^{131}I in RCS. The plot would be plant specific and in the technical specifications. The plot would reduce licensee's from the burden of generating a technical specification change each outage when inspections identify increased degradation in their steam generators. However, NRC approval would have to be obtained if a new or a different accident limiting accident were identified or the consequences of a previously analyzed accident changed or the assumptions which were the basis for the plot did changed.

Previously, when licensees wish to allow degraded tubes to remain in service through the next operating cycle, they are required to perform a dose assessment which determines whether the event induced leakage, in conjunction with the normal operating leakage, would result in either GDC 19 or Part 100 dose guidelines being exceeded. Depending upon the degree of degradation in the steam generators, licensees usually perform the dose assessment at the

technical specification values for the normal operating primary to secondary leakage rate and at the maximum instantaneous value of dose equivalent ^{131}I in the RCS and the 48 hour value for dose equivalent ^{131}I in the RCS. If use of the technical specification values result in either GDC 19 or Part 100 doses being exceeded then the licensee must either reduce the technical specification values for the maximum instantaneous value of dose equivalent ^{131}I and the 48 hour value for dose equivalent ^{131}I in the RCS or, alternatively, plug or sleeve tubes. Sometimes it is necessary to change the technical specification values in order that, in the event of an accident, neither GDC 19 nor Part 100 doses will be exceeded. Sometimes, a technical specification change may be required to include the limit for the event induced leakage. If a change to the technical specification values is required it necessitates a license amendment.

When the licensee performs the next inspection of the steam generators, it is mostly likely that such an inspection will show an increase in the number of degraded tubes because, once a degradation mechanism is present, conditions tend to degrade further. Again a dose assessment would be performed and, based upon the new value for the event induced leakage, the licensee assesses whether the dose guidelines of GDC 19 and Part 100 are met. Again, if either dose guideline is exceeded, the licensee is required to change the technical specification values for the maximum instantaneous value of dose equivalent ^{131}I and the 48 hour value for dose equivalent ^{131}I in the RCS or, alternatively, plug or sleeve tubes. Ultimately, a point is reached in the process where the degradation in the steam generators is so great that it requires that tubes be plugged or sleeved. The flex option offers an approach which limits the need for submitting many of these license amendment requests that would be necessary until the point whereby tubes are required to be plugged or sleeved.

The following is an illustration of how the flex methodology would be applied. In this example it is assumed that the licensee will be applying IPC to a given plant but it would be illustrative of any scenario in which event induced leakage applies.

> The licensee will select a RCS value based upon the maximum allowable value for the maximum instantaneous value for dose equivalent ^{131}I. In addition, the technical specification value normal primary to secondary operating leakage will be assumed and an event induced leak rate will be assumed. Based upon these values the licensee will calculate the control room operator, EAB and LPZ doses for the pre-existing spike case for a MSLB with a coincident loss of offsite power. The maximum allowable event induced leakage at the assumed RCS activity level for dose equivalent ^{131}I is determined by multiplying the assumed event induced primary to secondary leakage rate times the ratio of the dose criteria for the dose of interest to the maximum calculated dose at the location. A second RCS value for dose equivalent ^{131}I, smaller than the first, would be selected, the event induced leakage assumed and a similar calculation performed. Again, the maximum allowable leakage value for the assumed RCS value would be determined. This process would continue with a series of calculations performed for a number of a RCS values of dose equivalent ^{131}I until the allowable leakage exceeded charging pump

capacity. Then a plot would be made of maximum allowable primary to secondary leakage as a function of RCS activity level of dose equivalent ^{131}I. Maximum allowable leakage is never allowed to exceed charging pump capacity. RCS activity level of dose equivalent ^{131}I is limited to a maximum of 60 μCi/g.

The second step of the process would have the execution of a similar calculation for a MSLB with an accident initiated spike. The maximum allowed RCS value for the 48 hour value for dose equivalent ^{131}I, the technical specification value for normal operating primary to secondary leakage and an assumed event induced leak rate would be selected. Doses would be calculated at the EAB, LPZ and control room operator locations based upon the spike occurring following the accident. The maximum allowable event induced leakage at the assumed RCS activity level for dose equivalent ^{131}I would be determined by multiplying the assumed event induced primary to secondary leakage rate times the ratio of the dose criteria for the dose of interest to the maximum calculated dose for the location. A second smaller RCS value for dose equivalent ^{131}I would be selected, an event induced leakage assumed and a similar calculation performed. Again, the maximum allowable leakage value for the assumed RCS value would be determined. A series of calculations would be performed until at a given RCS value the allowable leakage exceeded charging pump capacity. These data points would be utilized to generate the plot in the technical specifications for the maximum allowable event induced primary to secondary leakage as a function of RCS 48 hour value of dose equivalent ^{131}I. However, in no cases would the leakage rate be allowed to exceed the charging pump capacity. RCS activity level of dose equivalent ^{131}I is limited to a maximum of 1 μCi/g.

Figures C.9.2-1 through C.9.2-3 provide examples of plots for three plants. These plots have been generated from actual IPC amendment requests for three different plants. These plots demonstrate that allowable leakage is plant specific.

With the flex option, licensees will also be required to perform dose assessments for SGTR events. Assessments should include a pre-existing spike case and an accident initiated spike case. The EAB, LPZ and control room operator doses would be compared to the dose guidelines of Table C.9-1. The SGTR dose assessments would be performed at the maximum allowed instantaneous value for dose equivalent ^{131}I and the maximum allowed 48 hour value of dose equivalent ^{131}I. Such an evaluation would be performed to ensure that the SGTR is not more limiting than the MSLB with respect to the maximum allowed technical specification values for dose equivalent ^{131}I and normal operating primary to secondary leakage.

Utilization of the flex program incorporates much of the dose assessment methodology contained in SRPs 15.1.5 and 15.6.3. The parameters which should be utilized in the flex option are shown in Table C.9.2-2. As noted from a review of this Table, adoption of the flex program requires several changes from the parameters in SRPs 15.1.5 and 15.6.3. Such changes include:

1. Utilization of the same dose conversion factors which are employed for the determination of dose equivalent ^{131}I in RCS in the calculation of doses. This was previously discussed in conjunction with the default option.

2. Limitation of the dose consequences based upon the accident rather than the case.

3. Utilization of an iodine spiking factor of 500 for the MSLB and 335 for the SGTR for the accident initiated spike cases.

Whereas, the SRP evaluation has the dose acceptance criteria a function of whether the event is an accident initiated spike case or a pre-existing spike case, the staff has established for the flex program the dose acceptance criteria to be a function of the accident. In the SRP approach, for the accident initiated spike case for either a SGTR or a MSLB, the acceptance criteria is 10% of Part 100 guidelines. For the pre-existing spike case for either the SGTR or the MSLB, the acceptance criteria is the full Part 100 guidelines. With the adoption of the flex program, the dose acceptance criteria is no longer a function of the case but rather a function of the accident. For the MSLB it will be the full Part 100 values and for the SGTR it will be 10% of Part 100 values.

The spiking factors which are to be utilized for the accident initiated spike cases are 335 for a SGTR and 500 for a MSLB. The value of 335 was obtained from release rate data collected by Adams and Atwood in a paper entitled, "The Iodine Spike Release Rate During A Steam Generator Tube Rupture". The value of 500 is the same release rate as that presently in SRP Sections 15.1.5 and 15.6.3. This value remain unchanged because there exists no data on an iodine spike associated with a MSLB and the models which have been proposed do not justify a different value. Since there presently exists no basis for utilization of another value, the value of 500 will continue to be used for a MSLB.

With the selection of the flex option, licensees should not have to perform a dose assessment every inspection cycle. Rather, based upon the determination of the event induced primary to secondary leakage rate, licensees will be able to determine, from the previously generated plot which has been incorporated into technical specifications, allowable RCS activity levels of maximum instantaneous dose equivalent ^{131}I and the 48 hour value of dose equivalent ^{131}I.

It should be noted that the plot in technical specifications is good so long as a new or different accident need not be considered or a new release pathway need not be considered. When such situations arise, if those situations result in a new limiting scenario, then an assessment must be submitted to the NRC for review and approval and a new plot for the technical specifications must be developed and submitted for NRC approval.

9.2.3 Technical Specifications

The STS and the improved STS (ISTS) contain specific values for the RCS

maximum activity level of dose equivalent ^{131}I, a 48 hour value of dose equivalent ^{131}I and a maximum primary to secondary leak rate during normal operations. For those licensees which chose to utilize the default option for the calculation of doses, the existing STS and the ISTS are sufficient. Therefore, no change to their existing technical specifications would be required

However, for those licensees which opt for the flex program, a change to their present technical specifications will be required. A plant which incorporates the flex program will contain in their technical specifications a figure which is a plot of total leakage, both normal operating and event induced leakage, as a function of the RCS activity of dose equivalent ^{131}I. This figure will be utilized when degradation mechanisms began to appear and total primary to secondary leakage is projected to be greater than normal operating leakage. Incorporation of this figure into the technical specifications will provide licensees the flexibility of operation to administratively limit themselves to either a lower leakage rate, if the fuel is degraded such that RCS activity levels are high, or to permit higher leakage rates if the RCS activity level is low due to fuel integrity being very good.

With respect to the technical specifications, Table C.9-3 presents the technical specifications required for the default case and for the flex program. The most limiting case for allowable leakage will also be the case which establishes the technical specification values.

Table C.9-1 Dose Criteria for SG Accidents

Default Methodology

Accident	Thyroid EAB/LPZ	Thyroid Control Room	Whole Body EAB/LPZ	Whole Body Control Room
MSLB				
1. pre-existing spike case	300	30	25	5
2. accident initiated spike case	30	30	2.5	0.5
SGTR				
1. pre-existing spike case	300	30	25	5
2. accident initiated spike case	30	30	2.5	0.5

Flex Methodology

Accident	Thyroid EAB/LPZ	Thyroid Control Room	Whole Body EAB/LPZ	Whole Body Control Room
MSLB	300	30	25	5
SGTR	30	30	2.5	0.5
Fuel Damage Accident	300	30	25	5

Table C.9-2 Parameters to Calculate Thyroid Doses

Parameter	Default/SRP	Deterministic/Flex
χ/Q	Site Specific @95%	Site Specific @95%
Breathing Rate	RG 1.4 Value	RG 1.4 Value
Dose Conversion Factor (DCF)	RG 1.4, RG 1.109, ICRP 30	ICRP 30
Reactor Coolant Activity (RCS)	60 μCi/g pre-existing spike 1 μCi/g accident initiated spike	curve generated with a maximum of 60 μCi/g for the pre-existing spike and 1 μCi/g for the accident initiated spike
Spiking Factor	500	500 MSLB/ 335 SGTR
Dose Limit (Thyroid)		
MSLB	300 rem pre-existing spike/ 30 rem accident initiated spike	300 rem
SGTR	300 rem pre-existing spike/ 30 rem accident initiated spike	30 rem
Maximum Allowable Leakage	1 gpm or 150 gpd per SG times the number of SGs	Variable, function of limitations of 48 hour TS value for dose equivalent ^{131}I and the maximum instantaneous value for dose equivalent ^{131}I in the RCS and the limiting dose exposure pathway and the limiting accident scenario.

Table C.9-3 Required Technical Specifications for Dose Assessment Portions of Steam Generator Rule

Parameter	Default Case	Flex Case
Maximum Activity Level Dose Equivalent ^{131}I, $\mu Ci/g$	60	Variable
48 hour value Dose Equivalent ^{131}I, $\mu Ci/g$	1	Variable
Normal Operating Leakage, Total	1 gpm or 150 gpd/SG	150 gpd/SG
Dose Conversion Factors for Defining Dose Equivalent ^{131}I	RG 1.4, ICRP 30, RG 1.109	ICRP 30
Allowable Leakage, Event Induced, gpm	NA	Variable, function of product of leakage and dose equivalent ^{131}I activity level, limiting accident and scenario and charging pump capacity
RCS Sampling Frequency following a 15% Power Change in 1 hour	Once per 4 hours	Once per 4 hours

Plant A

TS Plot of Allowable Leakage

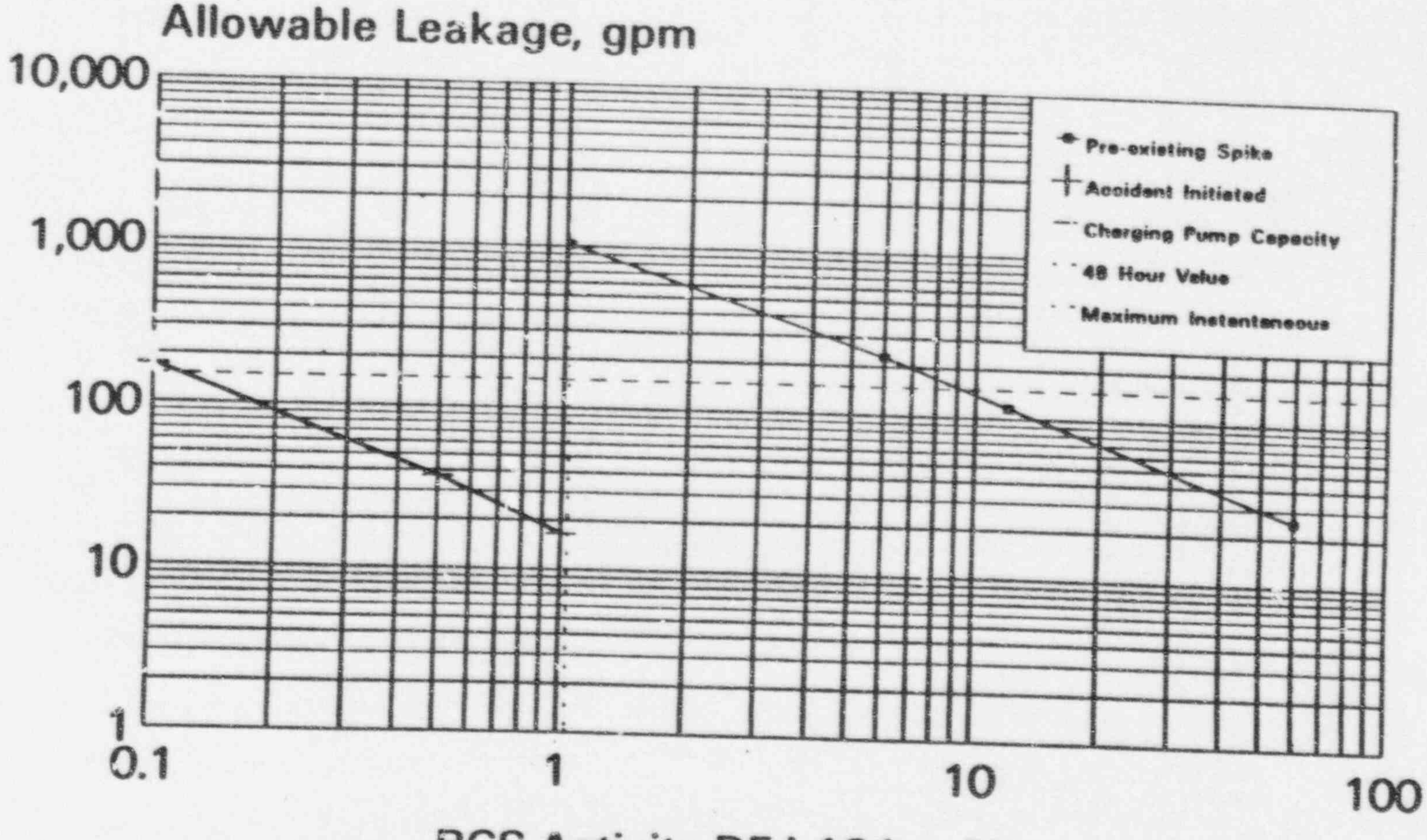


Figure C.9.2-1

Plant B

TS Plot of Allowable Leakage

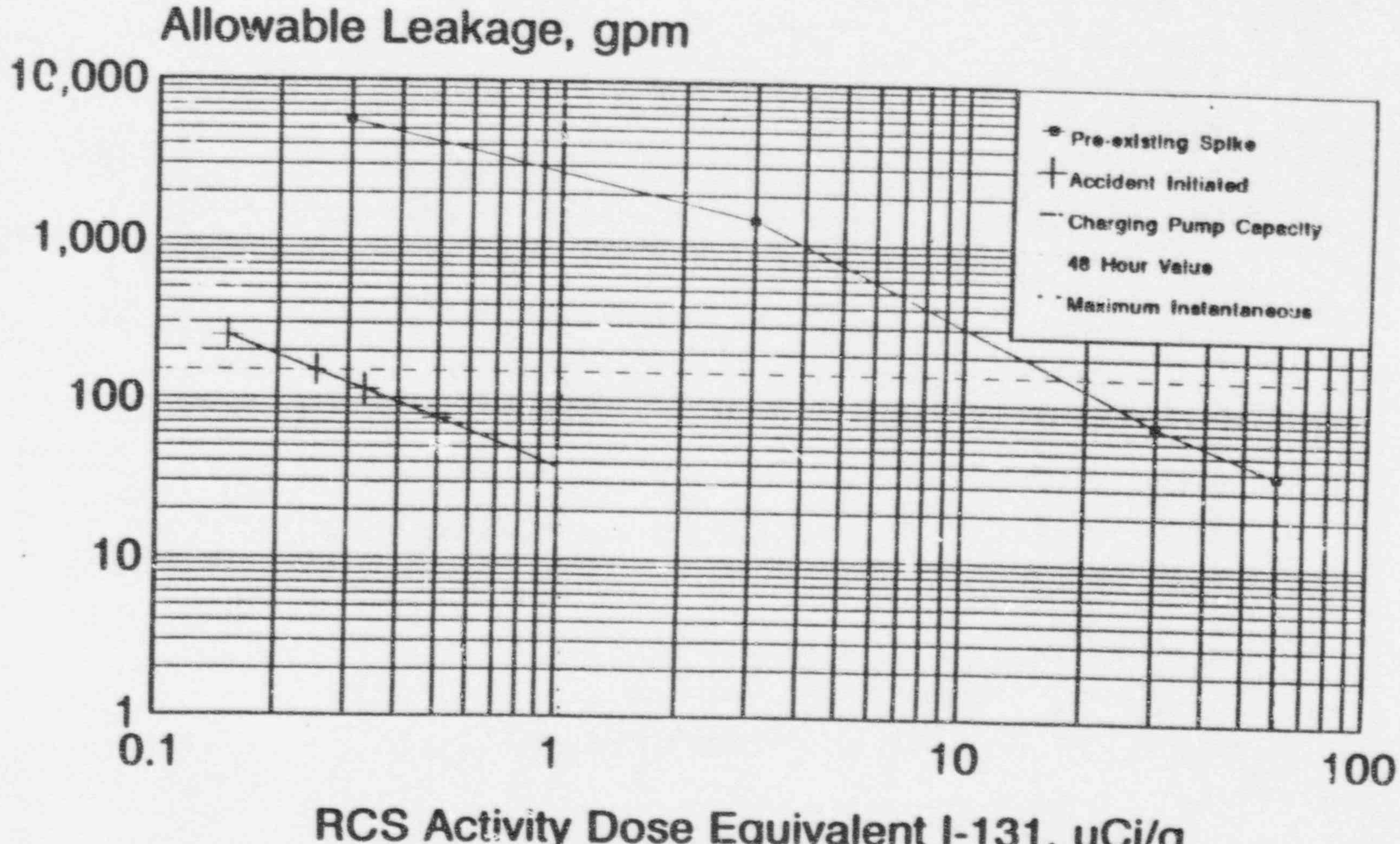


Figure C.9.2-2

Plant C

TS Plot of Allowable Leakage

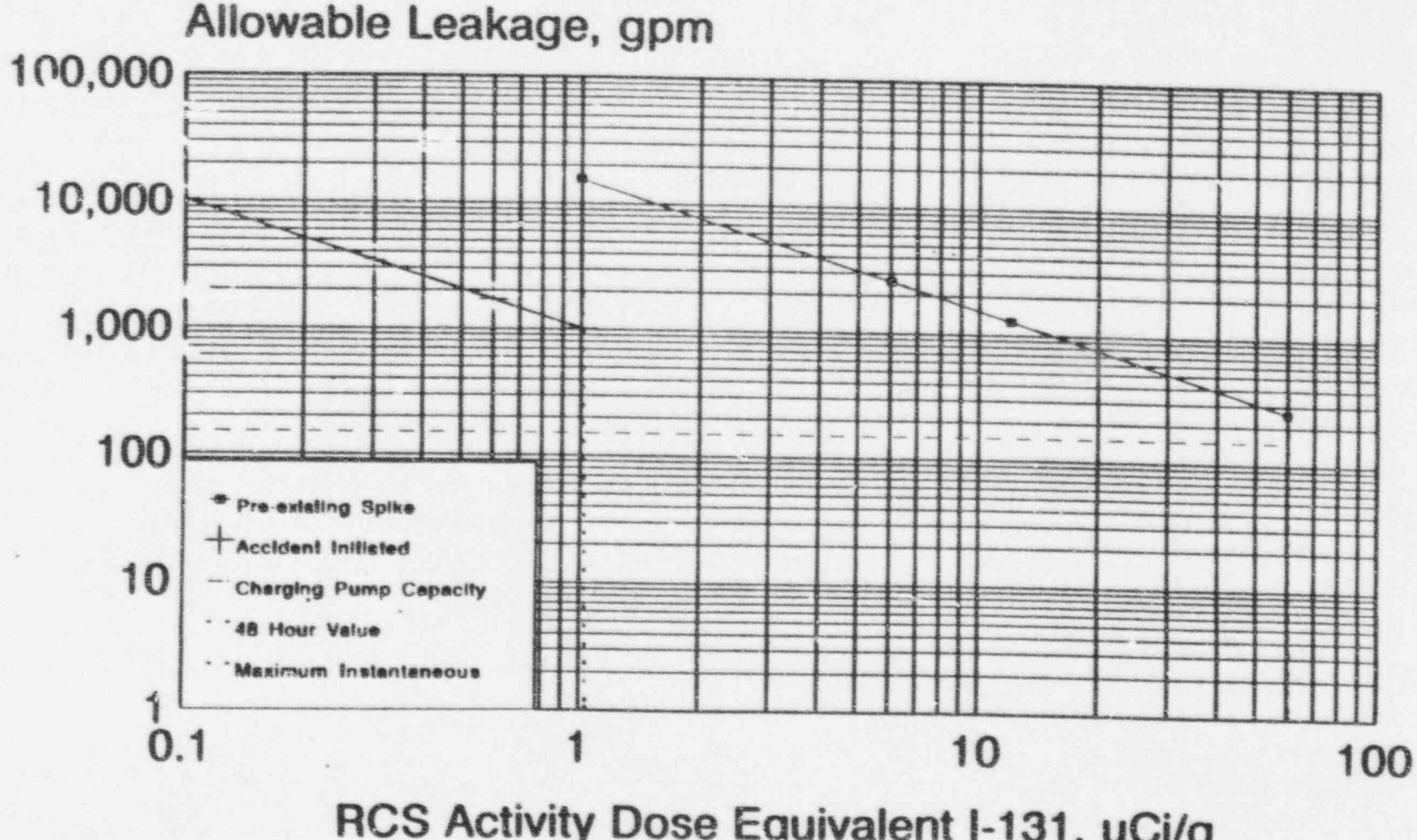


Figure C.9.2-3

C.10.0 Risk Assessment

General Design Criterion 14, "Reactor Coolant Pressure Boundary," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50 requires that the reactor coolant pressure boundary have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture. As a major portion of the reactor coolant pressure boundary, steam generator tubes must meet this requirement. Further, the steam generator tubes serve a unique dual role, functioning as reactor coolant and fission product containment boundaries. The containment function for tubes elevates their safety significance in the hierarchy of multiple fission product barriers, requiring that the tubes be capable of not only withstanding challenges assumed for other reactor coolant pressure boundary components, but also to provide protection from fission product release under conditions which could challenge reactor coolant pressure boundary integrity.

C.10.1 Approach:

Based on the staff analysis using example plant information and estimated steam generator tube conditions, a risk of thermally-induced SGTR may exist for plants operated under the proposed rule. The analysis performed by the staff to estimate tube failure potential (documented in NUREG XXXX) uses methods and information considered applicable to a representative facility.

While the staff analysis could not demonstrate that all facilities meet the surrogate safety objective through a generic analysis, plant-specific analyses should demonstrate the containment bypass vulnerability at a particular plant. In arriving at a containment bypass probability estimate, licensees should address uncertainties in areas such as predicted thermal-hydraulic conditions and tube degradation. The effects of a range of plant-specific factors should also be considered. Plant configurations could affect thermal-hydraulic conditions and event progressions, and tube degradation states could vary amongst facilities, but these could be specified for plant-specific analyses.

Plants operated under the rule should demonstrate that their facility does not present an undue risk of thermally-induced SGTR, or actions should be taken to reduce the risk to acceptable levels.

C.10.2 Risk Assessment Regulatory Position

The steam generator integrity rule requires that licensees take reasonably achievable measures to preserve the ability of tubes to serve as a barrier against the uncontrolled release of fission products. Licensees should strive for a fission product containment objective, including the potential for containment bypass, consistent with the Commission surrogate safety objective for large release. The reasonableness standard used to judge the adequacy of corrective measures taken to reduce bypass risk will be the resulting reduction of containment bypass frequency related to steam generator tube failure, relative to the surrogate safety objective for large release.

The steps outlined below offer the opportunity for licensees to use either a probabilistic analysis to show that the frequency of steam generator thermal challenge is very low, or an analysis demonstrating that tubes exhibit a low potential for failure if exposed to extreme conditions resulting from a core damage event. The staff analysis, although offering an acceptable approach, should not be considered definitive. Other analysis tools, and additional information should be considered, and plant-specific factors should be included in any similar analysis undertaken by a licensee to apply this regulatory guide.

C.10.2.1 Thermal Challenge Frequency

Based upon accepted probabalistic risk assessment (PRA) methods and data [reference Draft Guide 1061, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: General Guidance"], demonstrate that the potential for core damage events leading to steam generator tube thermal challenge in terms of the frequency of occurrence for sequences leading to high tube temperature and elevated tube differential pressure is less than 10^{-6} per reactor year. Unless specified in the Draft Guide referenced above, analysis inputs should be based on mean values in conjunction with appropriate uncertainty analysis.

C.10.2.2 Tube Failure Probability

Based upon a high confidence analysis assuming steam generator tube conditions associated with high pressure core damage sequences for the plant, demonstrate that steam generator tubes will have a low rupture potential (on the order of 10 percent is acceptable, if the tube thermal challenge frequency is shown to be no greater than 10^{-5} per reactor year.).

A high confidence analysis would use state-of-the art analysis tools and available experimental information to: (a) determine events of concern for steam generator tube thermal challenge, (b) predict reactor coolant system (RCS) thermal-hydraulic conditions, (c) predict high temperature RCS component performance, and (d) estimate conditional steam generator tube failure probability. The use of point estimates is sufficient for this analysis, provided the uncertainties listed below are addressed through sensitivity analyses or other means of demonstrating their significance.

The licensee analysis should address uncertainties and variabilities in at least the following areas:

a. Event Tree Quantification:

- Failure frequencies for important pressure relief components in the RCS and secondary systems (PORVs, MSSVs, ADVs).

- Failure frequency of reactor coolant pump seals and the magnitude of the resulting leak.

- Plant-specific configurations and procedures specifying operator

actions.

b. Thermal-Hydraulic Modeling:

- The range of maximum tube temperature and associated pressure expected during the event.

- The rate of heating for RCS components.

- The influence on thermal-hydraulic response of RCS piping configuration, RCS depressurization capability, secondary system pressure integrity, core configuration, steam generator design, and emergency operating procedures.

c. Tube Performance Model:

- Material factors which could affect prediction of creep failure for tubes and other RCS components.

- Failure modes other than burst should be considered.

- The model should be shown to apply to thermal-hydraulic conditions predicted for the events of concern.

- Account for the particular plant-specific degradation.

d. Flaw Distribution:

- Basis for plant-specific flaw size-based distribution given the current state-of-the art in tube inspection capability.

C.10.2.3 Corrective Actions

Licensees unable to demonstrate that their facility presents an acceptable risk of thermally-induced SGTR through the steps in (1) or (2), should take corrective actions to reduce the risk to acceptable levels. Plant modifications and procedural changes could be used.

Such actions might include reduction of the frequency of occurrence for sequences leading to steam generator tube thermal challenge. An acceptable means could include installation of safety grade RCS depressurization capability. Risk reduction could also be achieved by altering various factors that control thermally-induced tube conditional failure potential. However, to take benefit from such changes, licensee should perform an analysis to demonstrate the effect of the change on thermally-induced tube conditional failure potential.

Until licensees are able to demonstrate an acceptable risk from SGTR coincident with a core damage event using steps (1) or (2), alternate tube repair criteria defined in Section C.5.1 of this Regulatory Guide may not be implemented.

D. REPORTS TO NRC

1. Licensees should submit a report within 90 days of plant restart from each steam generator inspection outage with the following information:

a. description of scope of inspections performed, active degradation mechanisms found, NDE techniques utilized for each degradation mechanism and their status relative to the technique validation criteria in C.1.2.0, number of tubes plugged or repaired during the inspection outage for each active degradation mechanism, a description of the plug and/or repair designs employed, and the total number and percentage of tubes plugged and/or repaired to date and the effective plugging percentage in each steam generator.

b. description of the condition monitoring assessment, including methodology (can be referenced to a topical report) and results, for each active degradation mechanism. Where the condition monitoring assessment relies, in whole or in part, on non-eddy current test methods such as in-situ pressure testing and/or examinations of pulled tubes, technical justification should be provided concerning the scope and tube selection criteria used for applying these methods.

c. description of the operational assessment, including methodology (can be referenced to a topical report) and results, for each active degradation mechanism.

d. description of corrective actions, if any, implemented as a consequence of condition monitoring and/or operational assessment.

Licensees are encouraged to work together to develop a standard report format and content.

2. Failure of the condition monitoring assessment to confirm that the performance criteria of C.2.0 have been met should be reported to the NRC within 24 hours. In addition, a special report should be submitted prior to restart consisting of the information listed in D.1.a, D.1.b, and D.1.d as it pertains to the specific degradation mechanisms for with the performance criteria were not met.

3. Licensees should submit the analyses demonstrating risk for containment bypass as described in section C.10.0 and the implementation plan for any plant modifications deemed necessary based on the analysis results prior to the first plant restart following rule implementation.