Appendix J

Steam Generator Tube Integrity Findings
Significance Determination Process

This process is used in conjunction with Inspection Procedure IP 71111.08 "In-service Inspection," to determine the risk significance of findings which are performance deficiencies identified through the review of as found conditions.

Because most PRAs contain only the logic for risk due to spontaneous tube rupture events, there is not yet a wide-spread recognition of the risk impact that results from lesser levels of tube degradation. As a result, when the inspection issue is tube degradation the inspector will always advance to the Group 3 questions of Appendix B to IMC 0612.

Green - "very low safety significance"
(ΔLERF < 10^{-7}/RY)

Operation with $\geq$1 tube that should have been repaired as a result of previous inspection.

White- "low to moderate safety significance"
(10^{-7} < ΔLERF < 10^{-6}/RY)

1 tube that does not meet $3x\Delta P_{NO}$ integrity criterion (all plants)

Yellow - "substantial safety significance"
(10^{-6} < ΔLERF < 10^{-5}/RY)

W or CE plant with one tube that cannot sustain ΔP_{MSLB}

>1 tube that does not meet $3x\Delta P_{NO}$ integrity criterion (all plants)

$\geq$1 tube that does not meet $3x\Delta P_{NO}$ integrity criterion in 2 of last 3 inspections (all plants)

$\geq$ 1 SG violates "accident leakage" performance criterion (all plants)

Red - "high safety significance"
(ΔLERF > 10^{-5}/RY)

tube ruptures or is found to have been susceptible to rupture during normal operation (all plants)

B & W plant cannot sustain MSLB (combined loads from pressure + thermal differential)

Notes: A B&W plant with circumferential tube cracks may be susceptible to failure due to axial stresses induced by thermal transients. If circumferential cracks are found in the free-span of a B& W plant, the issue should be submitted for phase 3 analysis.

ΔP_{NO} = pressure difference across tube wall during normal operation

ΔP_{MSLB} = pressure difference across tube wall during design-basis main steam line break event

Attachment 1

I INTRODUCTION

This attachment to the SDP provides guidance for the assessment of licensee performance deficiencies which result in failures to meet licensing bases and regulatory commitments as identified through the in-service inspection program.

Following the steam generator tube failure event at Indian Point Unit 2 on February 15, 2000, the NRC developed a Steam Generator Action Plan to review the agency's short- and long-term responses, identify any improvements that should be made to processes and procedures, and implement them on defined schedules. Item 1.11.b.1 of the Plan is to "review how ISI [in-service inspection] results/degraded conditions should be assessed for significance by a risk-informed SDP [Significance Determination Process] and define needed revisions to the SDP." The Probabilistic Safety Assessment Branch has the lead for this sub-task.

II RISK INCREASES CREATED BY STEAM GENERATOR TUBE DEGRADATION

One of the difficulties with risk estimation for steam generator (SG) tube degradation issues is that most Individual Plant Examinations (IPEs) and other probabilistic risk assessments (PRAs) do not include logic models for all of the effects of the degradation.

Complete risk assessments of SG tube degradation require consideration of several types of core damage accident sequences:

1. Sequences initiated by spontaneous rupture of a tube. The sequence that result in core damage involve a variety of combinations of equipment failures and human mistakes. Most of the core damage sequences also result in containment bypass, but not all.

2. Sequences initiated by steam-side depressurization of an SG, which causes one or more degraded[1] tubes to rupture. These sequences result in core damage by similar combinations of equipment failures and human mistakes. Containment is usually bypassed by the combination of tube rupture and the cause of the steam-side depressurization.

3. Some core damage sequences created by initiating events and equipment failures that have nothing to do with the SG tubes. The core damage sequences of concern are characterized by relatively high reactor coolant system pressure and dry SGs at the time that fuel cladding oxidation occurs in the reactor core. These conditions subject the SG tubes to temperatures well above design values. At these abnormal temperatures, the tube material is weaker, and tube ruptures may occur if the tube strength has been degraded during normal operation. The effects of tube degradation on these sequences is an increase in the probability that containment bypass will occur for accidents already included in the base core damage frequency. They do not increase the core damage frequency.

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[1] In the context of this Appendix, the term "degraded" refers to any reduction in the structural/leakage integrity of a tube, regardless of the depth of the flaw. It is not intended to convey the special definition of a "degraded" tube used in the standard Technical Specifications.

4. Sequences caused by failure of the reactor protection system to stop the nuclear chain reaction when feed water is lost. These sequences are called loss-of feedwater anticipated transients without scram (lofw-ATWS) events. With additional equipment failures, they can produce reactor coolant system pressures that are high enough to cause other failures that lead to core damage. If the tubes are degraded, the high pressure may also rupture some tubes as well, creating a containment bypass.

Typical PRAs include only the first of these types of sequences, those initiated by spontaneous tube rupture events during normal operation. In the mid-1980s, NUREG-0844 identified the pressure-induced ruptures in the second and fourth types of sequences, and NUREG-1150 identified the high-temperature-induced ruptures in the third class of sequences. In the mid-1990s, NUREG-1570 collected all of these sequences in one place and evaluated them for a specific level of degradation. A few IPEs have been updated to incorporate the induced-rupture sequences, notably the Calvert Cliffs IPE.

There still is a problem with making the risk model logic for these sequences sensitive to the current degree of degradation of the steam generator tubes in a specific plant. Nearly all PRAs use the same frequency for the spontaneous rupture of a tube during normal operation. Intuitively, it seems that plants with known tube degradation problems should have higher spontaneous rupture frequencies than plants with new SGs and no degradation observed to date. However, to some degree, use of the average empirical frequency is justified by our experience that all of the tube rupture events have been surprises when they occurred. And, it will remain so, because a plant would not knowingly be operated with tubes that had degraded to the point that they cannot withstand three times the stresses of normal operation. Even when an inspection has revealed that the factor-of-three margin required by the plant's licensing basis has not been maintained during a previous operating cycle, it is difficult to relate the degree of degradation that actually is observed to a quantitative increase in the probability that tube degradation would have reached the spontaneous rupture point in that cycle. This makes it infeasible to base SDP color determination on the unquantifiable fluctuations in spontaneous rupture frequency for a specific plant.

This and other problems with risk quantification will be discussed in a later section.

III TUBE INTEGRITY REQUIREMENTS

Steam Generator tube integrity requirements occur in several forms. Current technical specifications are based on an out-dated assumption that the dominant forms of tube degradation are pitting and general wastage of the overall wall thickness. For the growth rates observed for these types of degradation and one-year fuel cycle lengths, limiting tube flaw depths to 40% of the wall thickness at the beginning of the cycle provides reasonable assurance that the tubes will meet the licensing basis requirements by the end of the cycle. Pits that penetrate the wall are limited in size by the technical specification limit on operational leakage. Licensing basis analyses assume that accident leakage is at the limit for operational leakage, and that the leak rate will not increase due to the accident. That is a valid assumption for pits, but not for cracks, which have become the dominant form of degradation in reactors today. If an accident produces higher than normal pressure difference across the tube walls, cracks may open. Flaws that did not leak during normal operation may begin to leak, and the rate of leakage may greatly increase through cracks that were already leaking slightly during normal operation. Also, crack depths have been observed to grow at much higher rates than was assumed for wastage.

It has been recognized for some time that the specific requirements in current technical specifications are prescriptive and out of date for the kinds of degradation mechanisms currently being experienced. These requirements have significant shortcomings with respect to ensuring that tubes are inspected before their integrity may be impaired. Among these shortcomings, the condition of the tubes is not directly evaluated relative to structural margin and accident leakage values assumed in the plant licensing bases. To address these shortcomings, the industry has developed a variety of technical guidelines on matters related to maintaining steam generator tube integrity. In addition, the industry has voluntarily adopted the NEI 97-06 initiative, "Steam Generator Tube Integrity Program." More recently, NEI has submitted a proposed generic licensing change package consistent with the implementation of this initiative. This initiative and proposed generic license change package integrates the industry guidelines into a performance based program for ensuring tube integrity. Under this approach, the condition of the tubing will periodically be assessed relative to performance criteria which are commensurate with tube integrity and with the current plant licensing bases. These criteria include:

1. All tubes shall maintain a margin of three against burst during steady state full power operation and a margin of 1.4 against burst during the most limiting design basis accident. For plants with U-tube SGs (Westinghouse and Combustion Engineering designs), the requirement effectively is to be capable of maintaining a pressure differential of either a) 3 times the normal operating pressure difference across the tube wall, ($3 \times \Delta P_{NO}$) or b) 1.4 times the pressure difference of the most limiting design basis accident, which is the main steam line break accident ($1.4 \times \Delta P_{MSLB}$), whichever is greater. For plants with straight-tube SGs (Babcock and Wilcox design), there are loads in addition to the pressure loads that must be considered. These loads arise during temperature and pressure transients that cause differential expansion and contraction of the tubes and shell, creating axial stress on the tubes.

2. During the most limiting design basis accident, the calculated rate of leakage (accident leakage) shall not exceed 1 gallon per minute (gpm). This typically applies to a single steam generator under the conditions assumed for a design-basis main steam line break accident. (For a few specific types of degradation in specific, confined locations, the NRC has approved alternate repair criteria that allow for specific higher accident leakage limits, using leakage calculations that assume the flaws are not confined.)

3. During operation, the maximum leakage from a single steam generator shall not exceed 150 gallons per day (gpd). This value has been found by experience to be appropriate to preempt rupture of a tube that is exhibiting leak-before-break type behavior, and it is not unduly burdensome. However, operational leakage is not necessarily coming from a type of degradation that is susceptible to rupture, and, on the other hand, some flaws have ruptured without leaking first.

Licensees currently determine their compliance with the first two criteria by calculations based on the tube in-service testing (ISI) data and/or by in-situ pressure testing at each SG tube ISI.

Inspection findings that involve failures to meet either of the first two requirements can be evaluated in terms of the risk that is incurred. Findings that involve operational leakage are not amenable to risk assessment until the cause of the leakage has been found and it is assessed with respect to the first two requirements.

IV RELATIONSHIPS BETWEEN TUBE DEGRADATION AND THE REACTOR OVERSIGHT PROCESS "CORNERSTONES"

When tube degradation reaches a level that prevents a tube from meeting its required pressure retention capability (3 x ΔP_{NO} or 1.4 x ΔP_{MSLB}), it is beginning to become susceptible to the accident sequences that induce tube rupture by high temperatures that would occur during core damage accidents. Excessive tube leakage during severe accident sequences may also alter the course of the sequence and cause gross tube failure, creating a containment bypass. This degree of degradation also makes the tube susceptible to rupture due to the extremely high reactor coolant system (RCS) pressures that can occur in some ATWS accident sequences, creating an increased probability for containment bypass for those sequences, too. Thus, this degree of degradation has an effect on the "Barrier Integrity Cornerstone."

When tube degradation reaches the level that allows a tube to rupture under the conditions of a design-basis main steam line break event, it has become susceptible to failure during anticipated operational occurrences such as steam system depressurization events. This is still considered a degradation of the "Barrier Integrity Cornerstone," but it involves additional terms of the risk equation to quantify the effect.

Finally, when degradation reaches the level that allows a tube to rupture during normal operation (or it could have ruptured if the pressure on the tube had been slightly increased by a practice used in normal operation), then there is an effect on the "Initiating Events Cornerstone" as well as the "Barrier Integrity Cornerstone."

V SCREENING STEAM GENERATOR TUBE DEGRADATION ISSUES THAT RESULT FROM AN INSPECTION

Because most PRAs contain only the logic for risk due to spontaneous tube rupture events, there is not yet a wide-spread recognition of the risk impact that results from lesser levels of tube degradation. As a result, when the inspection issue is tube degradation that doesn't meet margin requirements but is above the spontaneous rupture threshold, the inspector will advance to the risk-related questions in Group 3 Appendix B to IMC 0614.

VI TREATMENT OF SG TUBE ISI ISSUES THAT DO NOT PROVIDE DIRECT KNOWLEDGE OF TUBE CONDITION

Except when tubes rupture during normal operation, our knowledge of tube condition is limited to the results of the periodic tube inspections conducted by the licensees sometimes supplemented by in-situ pressure tests of a few tubes. If those inspections are not conducted in a manner that is adequate to detect tube degradation before it reaches significant levels, then a substantial risk increase can occur without our knowledge.

Regulatory requirements do not specifically address many of the technical aspects of how the licensee's SG tube ISI activities are conducted. Industry guidance has been developed for selecting specific ISI methods and practices that are adequate for specific plant conditions. However, the current guidance on how to do an effective tube ISI is not fully mature for all plant conditions. The overall intent of NRC requirements and industry guidance is to conduct tube ISI with sufficient frequency and detection capability to provide reasonable assurance that every tube will continue to satisfy all tube performance criteria until the next inspection.

Many NRC inspection issues are related to questions about the adequacy of the licensee's ISI and condition monitoring methods and practices with respect to the licensees' obligation under 10 CFR 50, Appendix B Criterion 16 to identify conditions adverse to quality. In cases where tube ISI and condition monitoring has not revealed any violation of the tube performance criteria, some NRC findings may still raise doubts about whether the ISI has been adequate to assure that all tubes meet the criteria, or that they will continue to do so by the end of the next inspection interval. Examples of this type of finding are: (1) the inspection technology used is not sensitive to a type of tube degradation that has violated the tube performance criteria at similar plants; (2) the "noise" level in the inspection signal is unusually large at a plant, and could mask the signal of a flaw that could grow to violate a performance criterion before the next inspection; (3) screening criteria for selecting tubes for in-situ pressure testing do not fully account for flaw size measurement error associated with non-destructive examination technologies, and 4) the number and/or severity of flaws fund significantly exceeded what was expected, based on the previous operational assessment.

For these types of inspection issue, we do not know the probability of tube failure under the various risk-related plant conditions because we do not have an adequate basis for assessing the physical condition of the tubes. In theory, if we had data on the number of times that the tubes had degraded to specific performance levels for a large number of <u>randomly selected</u> cases where inspection had been inadequate, we at least could make an estimate of the probability that the tubes have degraded (or will degrade) to various levels due to the lack of adequate inspection. However, that type of data is not available, so the probability of tube degradation to specific levels is not known as a function of the degree or type of licensee ISI performance problems.

Consequently, inspection issues related to inadequate ISI methods and practices cannot be assessed for risk significance when we have no direct knowledge of the degree of tube degradation that actually has occurred. Therefore, the new reactor oversight process (ROP) must provide a means, other than quantitative risk assessment, for the NRC staff to allot increased inspection effort on the basis of this type of inspection issue.

In accordance with the companion SGAP item 1.11.a, modifications are being made to the inspection procedures that facilitate appropriate inspector response to issues involving inadequate SG tube ISI. In addition to the infeasibility of assigning a risk increment to an unknown tube condition, there is a need for more rapid agency response than is achieved through the SDP procedures. Licensees can inspect the tubes only when the reactor is shut down and the SGs are opened. There is a very limited period of time during which the tube ISI is scheduled. If a licensee appears to be performing the ISI in an inadequate manner, timely agency and licensee responses are important to limiting licensee burden as well as maintaining public safety. The inspection procedures accomplish this by allocating additional effort to SG ISI from the band of allowable inspection effort within the base inspection program. Also, identification of these types of issues by regional staff will result in notification and involvement of headquarters specialists in DE/EMCB, which will focus additional effort by headquarters staff on the issues identified.

VII CONDITIONAL CORE DAMAGE PROBABILITY ESTIMATES FOR SG TUBE FAILURE EVENTS AND DEGRADED CONDITIONS

When risk-significant tube degradation is revealed by a tube failure during normal operation or by ISI results, the agency responds in accordance with the provisions of Management Directive 8.3. That directive specifies that the level of response is to be based on deterministic criteria and risk significance, "such as conditional core damage probability (CCDP)." In the case of SG tube degradation, the more appropriate risk measure would be the conditional probability of a large, early release (CLERP) of radioactive materials during a core damage accident. As discussed previously, SG tube degradation and failure events can substantially increase public risk with little or no increase in the core damage frequency.

The probabilistic calculations that are required to quantify the risk increase for the SDP process are essentially the same as those used to calculate a CCDP or CLERP. The following discussion will serve to illustrate both processes needed to support the ROP.

VIII QUANTIFICATION OF RISK INCREASES ASSOCIATED WITH SG TUBE DEGRADATION

As previously discussed, there are several types of accident sequences that can increase CDF and/or LERF due to tube degradation. As the degree of degradation becomes more severe, more of these sequences contribute to the risk increase because tube failure probabilities significantly increase for the physical conditions relevant to those sequences.

When tube degradation has reached the point that one or more tubes cannot withstand three times the pressure differential that occurs in normal operation ($3\Delta P_{NO}$), a tube integrity performance criterion has been violated. The $3\Delta P_{NO}$ level varies significantly from plant to plant, depending on the plant design and the number of tubes that have been plugged. It is approximately 4000 psi. The risk significance of the violation needs to be assessed as part of the ROP. However, the accident sequences to which tubes are vulnerable at approximately the $3\Delta P_{NO}$ level of degradation are not design-basis accidents. They include ATWS sequences and core damage sequences during which the fuel clad oxidizes while the RCS is not yet depressurized and the SGs are dry (high/dry core damage sequences). The $3\Delta P_{NO}$ tube integrity criterion was not established as the threshold for susceptibility to these sequences. Risk actually may increase before or after the tubes have degraded to this level, depending on several aspects of the plant design and current core fuel load parameters. This complicates the concept of assessing the risk of the licensee's "performance deficiency" because the licensee arguably is allowed to increase risk up to the point of the $3\Delta P_{NO}$ criterion. Thus, to be exact, the SDP risk assessment should subtract the risk at the $3\Delta P_{NO}$ degree of degradation from the risk at the level of degradation actually found.

This presents a problem, because the current capability for estimating risk from tube degradation for the high/dry sequences is not developed sufficiently to make such fine distinctions. In NUREG-1740, the Advisory Committee on Reactor Safeguards Ad Hoc Subcommittee on a Differing Professional Opinion concluded that "The staff does not currently have a technically defensible analysis of how steam generator tubes, which may be flawed, will behave under severe accident conditions in which the reactor coolant system remains pressurized." There are several crucial gaps in our technical knowledge that are now the subjects of Office of Nuclear Regulatory Research projects. These projects are listed with their estimated completion dates in item 3 of the SGAP. Industry's assessments for these sequences are not any more valid than the staff's assessments. Their results do serve to illustrate the wide range of results that have been obtained. For example, an analysis submitted for one Westinghouse plant concluded that high/dry core damage sequences would not cause tubes to fail if they were capable of withstanding design basis accidents, while another analysis for same type of accident sequences a Combustion Engineering plant concluded that tube failure would be ensured during the by flaws which are small enough to meet the $3\Delta P_{NO}$ criterion. In the first study, that degree of degradation was concluded to be insufficient to cause tube failures. In the other, a lesser degree of degradation was concluded to be severe enough to assure tube failures. In the first study, the licensee's results showed no change in risk as the tube degradation approached the $3\Delta P_{NO}$ strength requirement because tubes with that strength were calculated to survive during severe accidents. In the second study, there was no change in the risk at the point where tube degradation reached the $3\Delta P_{NO}$ strength requirement because stronger tubes were calculated to failed, so the risk from the high/dry sequences had already reached its maximum value at permitted levels of degradation.

So, each study concluded that there is no change in risk at the $3\Delta P_{NO}$ level of degradation, but for opposite reasons. The staff's current analyses fall between these two results, making our conclusions about risk increases sensitive to degradation near the $3\Delta P_{NO}$ level.

Similarly, models available from the staff's risk assessment for the ATWS rulemaking effort in the 1980s has been found to be outdated by changes in the fuel load characteristics for current reactor cores. Additional information on those sequences is currently coming from a Westinghouse application to change the NRC's fuel requirements to a risk-informed basis.

Because degradation appears to make tubes susceptible to ATWS and high/dry core damage sequences first, we anticipate that SDP risk assessments for all levels of degradation that violate tube integrity criteria will need to include these most difficult sequences. When degradation has become bad enough that tubes are susceptible to steam line breaks or normal operational stresses, the risk assessment results will probably be dominated by the additional sequences. However, because the licensee's can contest the staff's preliminary risk assessment results with their own analyses, which may tend to diminish the risk based on very specific aspects of a particular degradation event, it is important that the ATWS and high/dry sequences not be neglected. For example, even when a tube failure event during normal operation revealed that the Indian Point unit 2 plant was susceptible to all of the sequences that can be influenced by tube degradation, it still was necessary to include the high/dry sequences in order to determine the appropriate "color."

Similarly, the accident leakage limit originally was established for showing conformance with 10CFR100 dose guidelines during design basis accidents, without an understanding of the impact of tube leakage on the progression of "high/dry" type severe accidents. So, present knowledge does not provide a clear basis for estimating what the additional risk is at the regulatory limit for accident leakage. This, too, is a subject of on-going SGAP research.

Because of the need to address these sequences and the current problems with the methods for analyzing them, it is not feasible at this time to produce plant-specific, phase 2 SDP tools for SG tube degradation issues. This SDP provides a generic tool for assigning a preliminary "color" to inspection findings when tube degradation has violated one or more tube integrity performance criteria. Inspectors should feel free to request assistance from headquarters staff who are familiar with the most current knowledge from the SGAP research projects.

The SDP places typical tube degradation inspection findings in broad "color" groups. According to the ROP, "green" issues are those that have a ΔLERF below $1x10^{-7}$/reactor-year. "White" findings are in the ΔLERF range between 10^{-7} and 10^{-6}/reactor-year. "Yellow" findings are in the ΔLERF range between 10^{-6} and 10^{-5}/reactor-year. "Red" findings are those with ΔLERF above 10^{-5}/reactor-year. Because tube degradation that violates the $3\Delta P_{NO}$ performance criterion may make the tubes susceptible to high/dry core damage sequences that have a frequency in the low-10^{-5}/reactor-year range, any of these colors appear to be a possibility. However, the degree of degradation beyond the performance criterion, the fraction of a year over which this degree of degradation existed, and many plant-specific factors are important determinants for the risk in a specific case. Experience and engineering judgement have been used to produce the preliminary "colors" for findings that are susceptible only to these sequences. Babcock and Wilcox (B&W) reactors are listed separately for some findings because they have diferent frequencies for some important sequences. High/dry core damage sequences are less likely to produce high tube temperatures in B&W once-through SG designs than in the U-tube SG designs in Westinghouse (W) and Combustion Engineering (CE) plants. Also, B&W designs have higher frequency of steam-side depressurization events.

When one or more tubes has degraded to the point that they cannot sustain the pressure differential created by a steam-side depressurization event (ΔP_{MSLB}), it is necessary to include those sequences in the risk assessment, as well. The threshold for this sequence is the lowest <u>operable</u> pressurizer valve setpoint. In some plants, that will be a power-operated relief valve; for other plants where the PORVs are blocked or not installed, it will be a safety valve setpoint. Again, B&W plants differ significantly from the W and CE plants. B&W plants have experienced several events that produced pressures near these thresholds shortly after a reactor trip. Westinghouse plants have experienced a relatively smaller number of events (considering the numbers of each design in operation), and none that we are currently aware of produced such high pressure differentials across the tubes after a reactor tripped from normal operation. However, Westinghouse plant events are known to have produced similarly high pressure differentials across the tubes under other operational situations and lesser pressure differentials following trips from full power. On this basis the frequency of high pressure differentials on the tubes due to steam-side depressurizations is estimated at about 10^{-2}/reactor-year for B&W plants and about 10^{-3}/reactor-year for the U-tube designs. When degradation has made the tubes susceptible to rupture if a steam generator depressurizes, a depressurization event becomes much more difficult for the operators to handle. Considering the difficulty of the combined primary and secondary system failures, the probability for the plant operators failing to stop the sequence before core damage occurs is estimated to be about 10^{-2}. Thus, a tube susceptible to a steam-side depressurization for a year is estimated to produce a ΔCDF/ΔLERF of about 10^{-4}/RY for a B&W plant and about 10^{-5}/RY for a Westinghouse or Combustion Engineering plant. These values are well into the "red" range for B&W plants and at the yellow/red threshold for the U-tube plants. Since susceptibility is not expected to occur for an entire year in most cases, the U-tube plants have been assigned a preliminary "yellow" while the B&W plants are assigned a preliminary "red."

Based on staff judgement, degrees of degradation between the $3\Delta P_{NO}$ and ΔP_{MSLB} levels have been assigned to the yellow group in the SDP. The judgements made involve the expected potential for an ISI deficiency that allowed the observed level of degradation to develop to also have allowed other similar levels with the ΔLERF values in the "yellow" range. For example, if more than one tube does not meet $3\Delta P_{NO}$, there is a substantially increased probability that a tube could degrade to the point of not meeting ΔP_{MSLB}.

Finally, the amount of degradation that makes a plant susceptible to tube rupture during normal operation has been assigned a "red" color for all plant designs. Included in this color are tubes that would rupture at pressure differentials that are often encountered during normal plant operations, even if the tube did not actually rupture because the actual operations did not happen to include those pressures while the tube was susceptible. A probability of about 0.1 for encountering those pressures is sufficient to keep the ΔLERF estimate in the "red" category. The pressure threshold for this category is about 1600 psi for many plants. However, some plants may subject their tubes to much higher values, so plant-specific information should be used.

This appendix includes a green criterion for plant operation at-power with one or more tubes that should have been repaired or plugged, but were not. This criterion is intended to apply to either 1) a licensee's failure to identify a flaw that should have been identified as meeting the plugging limit with the data obtained in a previous inspection, or 2) a licensee's inadvertent failure to plug a tube that was identified for plugging. This criterion does not apply to the situation where a tube that is identified as flawed in a subsequent inspection can be found to have exhibited a detectable signal in the previous inspection data, unless the data from the previous inspection clearly indicates that the flaw exceeded the plugging limits at the time of the previous inspection. However, if the flaw causes the tube to fail the $3x\Delta P_{NO}$ requirement when it is found in the subsequent inspection, then SDP criteria listed under white, yellow or red will still apply. If it appears that a previous inspection was inadequate to properly characterize the condition of the tubes or that the inspection interval was too long to assure continued compliance with the performance criteria on the basis of the data obtained in the last inspection, the significance determination should be based on the nature and degree of the inspection process inadequacy, rather than on the worst flaw found by an inadequate ISI effort.

The attachment does not include entries for exceeding the operational leakage limit because that does not necessarily mean that a significant risk increase has occurred. When that limit is exceeded, the licensee must shut down the plant and find the cause. Once the cause is determined, it will be possible to characterize the problem in terms of the probability for rupture and the estimated rate of leakage at the specific conditions associated with the risk significant accident sequences. So, the significance can then be based on the entries for those findings in the attachment.

B&W reactors have an additional issue that is not relevant to the U-tube designs used by Westinghouse and CE. The B&W design uses straight tubes that can be put into tension or compression by thermal transients in the RCS, due to changes in the temperature difference between the tubes and the SG vessel shells, which are rigidly connected, parallel mechanical structures. For transients that cool the tubes significantly more rapidly than the shells, the tubes may experience axial tension loads that are high enough to cause tube failure at significant circumferential cracks. At present, significant circumferential cracking is not being found in the free span at B&W plants. If it is found, it should be carefully evaluated for the thermal loads as well as the pressure loads. The SDP does not attempt to assign a color to a finding of significant circumferential cracking in the free-span of the tubes in B&W reactors, but it does include a note to alert inspectors to submit the finding for Phase 3 analysis if it ever occurs.

The assigned colors for phase 2 are based on the assumption that the releases from core damage events with failed tubes have characteristics that are appropriately treated as part of the large, early release frequency. As modeled by the NRC in NUREG-1150, this is usually the case. Some plant's IPEs have found a few sequences that we agree are not appropriate to treat as part of the LERF. However, many plant IPEs treated some steam generator tube rupture sequences as non-LERF for reasons that the agency does not support. For example, Indian Point unit 2 IPE treats tube rupture sequences as non-LERF if the core melts while the SG relief valves still functions to control SG steam-side pressure. The licensee's logic is that their modeling shows that the resulting radioactive iodine release is only about 8% of the core inventory, which is less than the 10% threshold for LERF sequences proposed by EPRI. However, the staff's model for the same sequences in NUREG-1150 estimated that 14% of the core iodine inventory would be released. Further, the agency has never accepted the proposed 10% threshold as an appropriate definition for LERF. Therefore, when using an IPE for phase 3 SDP, it will be necessary to closely evaluate the bases for the LERF designations of the contributing sequences. Because there is a factor of a few thousand difference for the iodine release fraction between an SGTR core damage sequence and the core damage sequence where the containment function is successful, our current guidance is to treat sequences as if they are LERF if they are anywhere near the LERF type releases in magnitude and timing. Excluding sequences from the LERF category on the basis of small variations in the estimation of the core iodine fraction released is not realistic, considering the uncertainty of those small differences and the large difference between the magnitude of the LERF-type releases and the contained-sequences releases.

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END

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3. Risk Assessment of Severe Accident-Induced Steam Generator Tube Rupture, NUREG-1570, U. S. Nuclear Regulatory Commission, March, 1998.

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Attachment 2

Group 3 Screening Questions for SG Inspection Findings

Steam Generator Tube Inspection Results:

1. Did the plant operate at-power with one or more tubes that should have been but were not repaired or plugged based on previous tube inspection results.

2. Was one or more tubes found not to meet the required performance criterion for pressure (either 3 x the differential pressure at normal operating conditions or 1.4 x the differential pressure at the design-basis main steam line break accident condition, which ever is greater)?

3. For the “as found” condition of the tubes, was the calculated “accident leakage” rate higher than the applicable limit (performance criterion) in one or more steam generators?