Attachment 7

Appendix J

Steam Generator Tube Integrity Findings Significance Determination Process

1.0 INTRODUCTION

The significance determination process (SDP) provides a method to place inspection findings in context for risk significance in a manner that allows them to be combined with other plant performance results. This information is used to determine the level of NRC engagement in accordance with the Reactor Oversight and Assessment Process Action Matrix. This process is used in conjunction with Inspection Procedure IP 71111.08 "In-service Inspection," to estimate the risk significance of as-found plant conditions which may result in failures to meet licensing bases and regulatory commitments as identified through the in-service inspection program.

This SDP provides a generic tool for assigning a preliminary "color" to inspection findings when tube steam generator tube degradation has exceeded tube integrity performance criteria. It must be noted that the design of this SDP protects against false negative results, but can result in false positive results, i.e., a finding placed in context through SDP can result in a risk significance level (color) that exceeds the actual impact on public health and safety. All inspection findings related to tube degradation should be screened for SDP consideration (see Appendix B and Appendix E to MC 0612 for additional guidance on the screening process). Issues that have a preliminary risk significance of white, yellow, or red will be validated by a trained NRC risk analyst.

2.0 BACKGROUND

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. Therefore, it has been acknowledged that complete risk assessments of steam generator (SG) tube degradation requires 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 a SG, which causes one or more degraded[1] tubes to rupture. These sequences result in core damage by

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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.

similar combinations of equipment failures and human mistakes. Containment bypass is usually by the combination of tube rupture and the cause of the steam-side depressurization.

3. 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.

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 only account for the sequences 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 plant-specific PRAs have been updated to incorporate the induced-rupture sequences. This SDP incorporates information obtained from the NUREGs and available industry information to provide a generic tool for assigning a preliminary "color" to inspection findings when tube degradation has violated one or more tube integrity performance criteria.

2.0 GUIDANCE FOR SDP USE

This SDP places typical tube degradation inspection findings in broad "color" groups. According to the ROP, "green" issues are those that result in a ΔLERF below 10^{-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 $3\Delta P_{NO}$ (3 times the maximum differential pressure across tube during normal operation) 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 are possible. 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 different 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 plants have a higher incidence of steam-side depressurization events.

When one or more tubes has degraded to the point that they cannot sustain the maximum pressure differential expected during a design basis main steam line break event(ΔP_{MSLB}), it is necessary to include those sequences in the risk assessment, as well. The threshold for this sequence is the lowest operable 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 assumed frequency of secondary side depressurization 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 steam-side depressurization for a year is estimated to produce a ΔCDF/ΔLERF of about 10^{-4}/reactor-year for a B&W plant and about 10^{-5}/reactor-year 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."

Color	ΔLERF/Reactor-year	Inspection Finding
RED	$\Delta LERF > 10^{-5}$ new term need definition	Tube rupture occurs, Tube(s) found during testing to have been susceptible to rupture during normal operations, **or** Tube(s) found during testing that could not sustain ΔP_{MSLB} **(B&W)**
YELLOW	$10^{-6} < \Delta LERF < 10^{-5}$	One tube that cannot sustain ΔP_{MSLB} **(W and CE)**, Two or more tubes that do not meet $3x\Delta P_{NO}$ integrity criterion, One or more tubes that do not meet $3x\Delta P_{NO}$ integrity criterion in 2 of last 3 inspections, **or** One or more SGs that violates "accident leakage" performance criterion
WHITE	$10^{-7} < \Delta LERF < 10^{-6}$	One tube that does not meet $3x\Delta P_{NO}$ integrity criterion
GREEN	$\Delta LERF < 10^{-7}$	One or more tubes that should have been repaired as a result of previous inspection.

Notes: 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.

B&W plants 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.

Simplified Explanation of Risk Assessments Supporting Draft Steam Generator Phase 2 SDP Table

Green Findings:

- ***Tube that does not satisfy plugging/repair limit was not plugged/repaired before return to service, but degradation at end of cycle does not lead to tube failing to meet 3 x ΔP_{No} margin***

  Risk evaluation is presumed to be less than 1 x 10^{-7}/RY, based on calculations, below for higher levels of degradation.

White Findings:

- ***Degradation that does not meet 3 x ΔP_{No}***

  High/Dry part of CDF typically = 1-to-2x10^{-5}/RY

  Probability of secondary depressurization during high/dry sequence ≈ 0.1

  Probability of tube being in high temperature position = 0.5

  Probability of tube failure at high temperatures during high/dry sequence ≈ 1

  So, ΔLERF = 1-to-2x10^{-5}/RY x 0.1 x 1 x 0.5 = 5x10^{-7}-to-1x10^{-6}/RY

Yellow Findings:

- ***Multiple degradations (in one inspection or over multiple inspections) that do not meet 3 x ΔP_{No}***

  There are multiple rationales for this shift in significance level when more than one tube does not meet margin requirements. The numerical rationale for multiple tubes in one inspection can be seen by the increase in the probability that at least one of the tubes will see the highest temperatures during a high/dry core damage sequence. An additional rationale is based on increasing probability that a tube could degrade to the degree of not sustaining ΔP_{MSLB} if the deficiency persistence and degradation rates combine to produce multiple instances of failure to meet 3 x ΔP_{No} margin.

- ***One or more SGs violate "accident leakage" performance criterion***

  This criterion is intended to be somewhat conservative, pending completion of research efforts. Numerically, it is assumed that leakage at this level would be capable of making the tube failure probability = 1 for a flaw at any location during high/dry accident sequences with the secondary depressurized, raising the ΔLERF above 1x10^{-6}/RY. It is important to note that a flaw which is too short to rupture at normal operating temperatures may still be long enough to rupture at severe accident temperatures.

Leakage of single flaws at design basis "accident leakage" limits can be indicative of a flaw that is sufficiently large to rupture at severe accident temperatures.

- ***Degradation that makes tube susceptible to secondary depressurization events***

  CCDP for SG ruptures induced by secondary depressurizations = 10^{-2} (based on NUREG-1570 work on human error probabilities)

  Depressurization event frequencies for U-tube type RCSs = 10^{-3}/RY

  Credit for degradation not existing for full year ≈ 0.5

  So, ΔCDF = 10^{-3}/RY x 10^{-2} x 0.5 = 5 x10^{-6}/RY

  and ΔLERF = ΔCDF + ΔLERF from "white" degradation level calculation

  <u>Exception for B&W plants</u> with tube that cannot sustain ΔP_{MSLB},

  secondary depressurization frequency = 10^{-2}/RY

  So, ΔCDF = 10^{-2}/RY x 10^{-2} x 0.5 = 5 x10^{-5}/RY and significance level becomes "red"

<u>Red Findings</u>:

- ***In B&W plants, degradation that makes tube susceptible to secondary depressurization events***

  [See exception under "yellow" category directly above]

- ***Degradations leading to tube ruptures***

  CCDP for spontaneous tube ruptures = 1x10^{-4} (based on NUREG-1150 PRAs)

  For degradations leading to ruptures, frequency of occurrence of rupture in last year = 1.

  So, ΔCDF = 1 x 1x10^{-4}/RY

  and ΔLERF = ΔCDF + ΔLERF from "yellow" and "white" degradation level calculations

- ***Degradations that make a tube susceptible to tube rupture during normal operation***

  For degradations that would fail at differential pressures that have a probability of 0.1 for occurrence during normal operation,

  ΔCDF = 0.1 x 1x10^{-4}/RY = 1x10^{-5}/RY

  and ΔLERF = ΔCDF + ΔLERF from "yellow" and "white" degradation level calculations