WHITEPAPER IN SUPPORT OF

Alternate Requirements for Classification, Inservice Inspection, Pre-service Inspection and Repair/Replacement Activities

ASME Section XI
Working Group on the Implementation of Risk-Based Examinations
Item No. RI-02-02

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In particular, the support of Alex McNeill (Dominion Resources), Gary Belew (TVA), Gary Park (NMC) and Hien Do (Exelon) in providing plant specific experiences and reviews was invaluable.

SUMMARY

This action represents the next evolution of the use of risk-informed technology into Section XI requirements. This action builds upon the work done at ASME Section XI, the industry and the USNRC in developing and implementing risk-informed inservice inspection, pre-service inspection, classification and repair/replacement activities. As such, this action provides a balanced and integrated alternative to existing requirements for pressure boundary classification, pre-service inspection, inservice inspection and repair/replacement activities.

Experience gained over the last thirty years from plant operation, the understanding of Nondestructive Examination (NDE) capabilities and methods, the use of Probabilistic Risk Assessments (PRAs) and their insights, as well as an enhanced understanding of pressure boundary reliability and those mechanisms (including their causes) that adversely impact pressure boundary reliability has put the Code in a position today to develop effective changes to classification, pre-service (PSI), inservice inspection (ISI) and repair/replacement (RRM) requirements which can reduce undue burden without compromising safety. In most situations, if not all situations, the alternative requirements contained herein will result in an increase in component reliability as compared to existing Code requirements.

The changes that are presented in this action are supported by:

- the operating performance of the nuclear fleet,
- insights gained from the application of the risk-informed inservice inspection code cases (N560, N577 & N578) to almost fifty units,
- approval of the extension of the technology to break exclusion requirements/high energy line break (BER/HELB),
- trial use of the risk-informed classification/RRM codes cases (N660 & N662),
- knowledge of the type of degradation and thus identification of effective examination requirements, and

- knowledge of the type of degradation and thus identification of effective repair/replacement strategies.

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2. ASME Code Case N577, "Risk-Informed Requirements for Class 1, 2, or 3 piping, Method B" Section XI, Division 1, dated September 1997.
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INTRODUCTION

Over the last thirty years there have been significant gains in the understanding of pressure boundary component integrity, factors that impact component reliability, the impact of inspections and the type of inspection, as well as risk assessment insights related to operating nuclear power reactors. This experience has brought about changes related to operating and inspection requirements including changes to Section XI requirements, augmented inspection programs mandated by the regulator as well as plant specific actions taken by individual owners.

For Section XI programs, these efforts have included revised code cases (References 1, 2, and 3) and the development of pilot and follow-on plant specific applications (References 4, 5, 6 and 7). For NRC mandated programs, these efforts have included integration with risk-informed ISI programs (Reference 8), performance based initiatives (Reference 9) as well as extension to new areas including break exclusion/high energy line break BER/HELB requirements (Reference 10).

More recently there has been a focus on what has been termed "special treatment" requirements associated with nuclear systems, structures and components (SSCs). Both the industry and USNRC have embarked on efforts to revisit these requirements in light of their contribution to plant and public safety (Reference 11). ASME has been an important contributor to these efforts, including the development of trial-use code cases (References 12 and 13). These efforts have provided a clearer understanding of those issues that impact pressure boundary reliability, the role of inservice inspection (method, technique, etc.), identification of high value-added treatment requirements as well as the burden associated with low value-added treatment requirements.

The action discussed in this whitepaper takes advantage of the aforementioned work and proposes a balanced and integrated code action that reduces undue burden while ensuring plant safety. This action was in part spurned on by the USNRC's Advisory Committee on Reactor Safeguards (ACRS) who in 1999 chided the industry as being "overly timid" in implementing risk-informed technology (Reference 14).

It is interesting to note that PRA technology and inservice inspection requirements have a somewhat parallel history. The first concerted inservice inspection document, Inservice Inspection of Nuclear Reactor Coolant Systems was issued in 1974 (Reference 15). This document contained criteria for the use of UT examinations, flaw acceptance standards, flaw evaluation standards and rules for repair/replacement activities. While the defining document in application of risk technology to nuclear power plants (WASH-1400) was also developed in the early 1970s and published in 1974 (Reference 16).

Since that time there have expansion of these technologies including:

- 197X – expansion of SXI reqts to Class 2 and 3 pressure boundary components (Reference 17),
- 197X – expansion of SXI/O&M to pump and valves (Reference 18),
- 1979 – TMI study (Reference 19),
- 1981 – Fermi Study(Reference 20),
- 1982 – Zion Study (Reference 21),
- 1982 – Indian Point Study (Reference 22),
- 1983 - Seabrook PSS (Reference 23),
- 1988 – Generic Letter 88-20, (Reference 24),
- 1989 – NUREG-1150, Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants, (Reference 33),
- 1989 - Generic Letter 88-20, Supplement 1(Reference 24),
- 1990 - Generic Letter 88-20, Supplements 2 and 3(Reference 24),
- 1991 - Generic Letter 88-20, Supplement 4(Reference 24),
- 1995 – Final Policy Statement on Probabilistic Risk Assessment (Reference 25),
- 1996 – Code Case N560 (Reference 1),
- 1997 – Code Cases N577 and N578 (References 2 and 3),
- 1998 – Whitepaper on Risk-Informed and Performance-Based Regulation. (Reference 26),

Experience gained over the last thirty years from plant operation, the understanding of Nondestructive Examination (NDE) capabilities and methods, the use of Probabilistic Risk Assessments (PRAs) and their insights, as well as an enhanced understanding of pressure boundary reliability and those mechanisms (including their causes) that adversely impact pressure boundary reliability has put the Code in a position today to develop balanced, integrated and effective changes to classification, pre-service (PSI), inservice inspection (ISI) and repair/replacement (RRM) requirements which can reduce undue burden while continuing to ensure plant safety. In most situations, if not all situations, the alternative requirements contained herein will result in an increase in component reliability as compared to existing Code requirements.

The changes that are presented in this action are supported by:

- the operating performance of the nuclear fleet,
- insights gained from the application of the risk-informed inservice inspection code cases (N560, N577 & N578) to almost fifty units,
- approval of the extension of the technology to break exclusion requirements/high energy line break (BER/HELB),
- trial use of the risk-informed classification/RRM codes cases (N660 & N662),
- knowledge of the type of degradation and thus identification of effective examination requirements, and
- knowledge of the type of degradation and thus identification of effective repair/replacement strategies.

BASIS FOR PROPOSED ACTION

This section will define and provide the technical basis for each of the four elements of this action. As previously discussed, these four elements consist of:

- classification requirements,
- pre-service inspection requirements,
- inservice inspection requirements,
- repair/replacement activities.

<u>Element 1 – Classification Requirements</u>

Definition: Items (e.g. welds, piping components, valves, pumps and associated supports and appertunites) shall be classified as either category A or B items. Category A (safety significant) items shall consist of those items that meet one or more of the following conditions:

- Class 1 (i.e. reactor coolant pressure boundary > 1NPS).

- part of the decay heat removal pressure boundary function consisting of the RPV out to the first component located outside containment that is capable of remote action (close valve, trip pump). This does not include PCCW/service water or connections supporting the purification function (e.g. CVCS).

- that portion of the feedwater system (> 4NPS) within the scope of Section XI from the steam generator to the outer containment isolation valve/boundary restraint.

- within the break exclusion region for high energy piping systems which is defined as the piping (> 4NPS) between the inner and outer containment isolation valve/boundary restraint.

Category B (low safety significant) items shall include all other items within the scope of the Section XI program not classified as Category A.

Technical Basis:

Table 1 provides a listing of every unit in the USA that has received permission from the USNRC to implement a RI-ISI program, as of February, 2003. Several of these units were pilot plant applications developed prior to generic USNRC approval of the RI-ISI methodologies. This table summarizes the plant-specific information database from which a number of the insights for this action were drawn.

Table 2 presents the Class 2, 3 and NNS inspections identified as a result of the application of the RI-ISI process. The purpose of this table is to identify any outliers that may not be adequately addressed as part of the scope discussed above. This table also provides a framework for understanding the justification as to why the scope discussed above is reasonable. This includes the availability of other programs and processes for addressing pressure boundary integrity (e.g. flow accelerated corrosion programs).

Specific conclusions drawn from the information summarized in Table 2, on a system by system basis, is as follows:

- the auxiliary/emergency feedwater (AFW/EFW) system was identified at 5 units and totaled 25 inspections. Eight of these experience CST head pressure and alarm in the control. Nine locations (three units) were identified as medium risk and their contribution to plant risk was on the order of 1E-10/yr. For the fifth unit, the system's importance was driven by its susceptibility to FAC, which is a requirement of this action. In addition, repair/replacement requirements of this action will assure that these SSCs continue to meet structural integrity requirements. As such, the classifications and treatment requirements for this system are appropriate.

- the auxiliary steam and blowdown (AS/BD) systems were identified at 4 plants (*still need to confirm Watts Bar, SQN1 & SQN2*). For one unit, as a result of an update, the auxiliary steam locations are no longer high safety significant. In addition, a major portion of the blowdown system was initially assumed to high safety significant as a result of conservatively assuming all equipment in the local vicinity failed as a result of the postulated failure. In addition, significant portions of these systems are addressed by the BER criteria for category A items of this action. The remainder of these systems would also have been assessed as part of the IPE requirement and if shown to be safety significant, then classified as category A per this action. Also, the FAC program requirement of this action requires additional inspections in these systems, where appropriate. Thus, the classification and treatment requirements of these systems are appropriate.

- the component cooling water (CC/CCW) system was identified at 4 units (DC1, DC2, MP3 & Surry1). In the first two cases, which were identified as medium risk, these locations had very low probabilities of failure (i.e. < 1E-08), for the third case, MP3, these locations did not show up in Table 3.4-14 *(Check with Ray).* For the fourth case, these locations were added due to three reasons. 1) conservative modeling due to LERF considerations, 2) only a single containment isolation valve being available (i.e. not a core damage concern) and 3) postulated rupture of RCP thermal barrier cooling loops. Each of these issues would be addressed by the IPE requirement of this action. *Specifically, isolation of RCP thermal barrier ruptures were generically addressed by the NRC/industry in the 198X (list IEB or GL number).* As such, the classifications and treatment requirements of this action for this system are appropriate.
- the charging (CH/CVCS) system was identified at 6 plants. Four of the six plants identified these as a medium risk, with very low failure probabilities. For one of the two remaining units, these locations were 4 NPS socket welds with risk reduction worth values (RRW) of 1.000 and therefore a negligible contributor to core damage risk. It was added to the listing because it consisted of a segment with a single containment isolation valve. However, it does receive Appendix J containment leak rate testing which is the most effective means of monitoring containment integrity. For the final unit *(MP3 - Ray)*, this system did not show up in Table 3.4-14 *confirm with Ray.* As such, the classifications and treatment requirements of this action for this system are appropriate.
- the core spray (CS/CSL) system was identified at 2 units. These were all medium risk locations. On average, these locations represent a 1E-10 core damage risk. As this action will maintain structural integrity requirements for these SSCs and additionally require that repair/replacement activities minimize challenges to pressure boundary integrity, the classification and treatment requirements proposed by this action for this system remain appropriate.
- the containment spray (CSS/QSS/CSSV/CTN) system was identified at 10 units. In each case they were assigned very low failure probabilities and for four of the nine units assigned as medium risk. For three other units (MG1, MG2 & WB1), they were very low risk contributors except for a sensitivity cases when operator action was assumed to be guaranteed failure and for one of the units were as a result of an overly conservative application. As discussed above, repair/replacement requirements of this action will continue to assure that these SSCs meet structural integrity requirements. As such, the classifications and treatment requirements for this system are appropriate.
- the emergency condenser (EC) system was identified at 1 unit. This single inspection location is within the break exclusion region as defined by this action. As such, the classifications and treatment requirements for this system are appropriate.
- the feedwater (FW/MFW) system was identified at 14 units. The portion of the feedwater system identified as important is contained within the Category A definition of this action and/or addressed by the FAC requirements of the action. As such, the classifications and treatment requirements for this system are appropriate.
- the high pressure core injection/isolation cooling (HPCI/ICS/RCIC) system was identified at 5 plants. These were all medium or low risk locations, primarily due to potential susceptibility to thermal fatigue. On average these locations represent a 1E-10 core damage risk. As this action will maintain structural integrity requirements for these SSCs and additionally require that repair/replacement activities minimize challenges to pressure boundary integrity, the classification and treatment requirements proposed by this action for this system remain appropriate.
- the high pressure safety injection (SIH/HHI) system was identified at 2 plants *(MP3/Surry – confirm results)*. In each case these locations had a very low probability of failure (i.e. < 1E-08). A number of these segments see RWST head and/or normal charging flow and

therefore would alarm in the control on losses of inventory and thus would not go undetected. A number of other segments were shown to be low risk contributors but based upon operations input (i.e. requesting "a complete flowpath from the RWST to the RPV") were assigned to the high risk category. Existing plant programs provide adequate control of these SSCs from a pressure boundary integrity perspective. The repair/replacement requirements of this action will assure that these SSCs continue to meet structural integrity requirement and therefore the classification and treatment requirements of this action are appropriate.

- the low head safety injection (LHI/LPSI/SIL) system was identified at 3 plants. For the first plant (ANO-2), all this piping was medium risk (CDF ~ 1E-10 per location) and a large portion would be considered category A by this action (i.e. shutdown cooling function). For the second plant, 5 locations were identified and also fulfill the SDC function *(check with Ray)*. For the remaining plant, four of the seven locations are connected to the RWST and would experience tank head pressure and therefore leaks would alarm in the control room as discussed above. The remaining locations, are under review as part of a program update and appear to be most likely being removed from the high safety significance classification. Therefore, the classification and treatment requirements of this action are appropriate.
- the main steam (MS) system was identified at 4 plants and totaled 7 inspections. For one unit, these locations are on the steam supply to the turbine driven EFW pump. This flowpath is used on a frequent basis and tested accordingly. Thus, an inspection once every ten years is of negligible benefit. For another unit (BFN2), two locations were randomly selected to support defense in depth considerations. A portion of the main steam system is defined as Category A per this action and therefore would capture these inspections. For another unit, these locations were identified as low risk locations and for the final unit, a single inspection was added for system level delta risk considerations. Therefore, the classification and treatment requirements of this action are appropriate.
- the reactor coolant (RC) system was identified at 2 units. *McGuire*? Thus, the classification and treatment criteria for this system are appropriate.
- the decay heat recirculation (Recirc/RH/RHR/RHS) system was identified at 18 plants. These locations are generally medium or low risk with no identified degradation mechanism. There are some locations identified as potentially susceptible to thermal fatigue during initiation and operation of shutdown cooling. As such, because of the potential for thermal fatigue and the multiple functions of this system, a large portion of this system is classified as Category A per this action. *A single unit (Clinton) identified 10 locations susceptible to FAC. Need to confirm whether these are really cavitation, if so, then the risk significance drops from high to medium and medium to low. Either way, the FAC program as required by this action is the proper treatment for this mechanism.* Those portions classified as category B per this action are small contributors to plant risk (~1 E-10). As such, the classification and treatment requirements of this action are appropriate.
- the RS (RS) system is what? [*Check with Alex*] and was identified at X plants and totaled XX inspections,
- the reactor water storage tank (ECC/RWST) system was identified at 4 units and in each case had a very low probability of failure (i.e. < 1E-08). These segments see RWST head and therefore would alarm in the control room on losses of inventory. Thus, these events would not go undetected. Existing plant programs provide adequate control of these SSCs from a pressure boundary integrity perspective. In addition, repair/replacement requirements of this action will assure that these SSCs continue to meet structural integrity requirements.
- the safety injection (SIS) system was identified at 7 units (four STARS units plus Watts Bar and SQN1 & SQN2). For four of the units, these were assigned to the medium risk category and had a very low failure probability. Repair/replacement requirements of this action will

assure that these SSCs continue to meet structural integrity requirements. As such, the classifications and treatment requirements for this system are appropriate. *Discuss Watts Bar, SQN1 & SQN2.*

- the service water (SWS/ESW) system was evaluated at six units. Except for one inspection location, the important contributor to pressure boundary reliability, is the plants response to localized corrosion. The lone exception is a single inspection for local cavitation, which may already be addressed by existing FAC/LC programs. Regardless, the treatment requirements of this action require repair/replacement activities to assess the potential for cavitation prior to implementing plant changes. As such, the classification and treatment requirements for this system are appropriate.
- the chilled water (VS) system was identified at 1 plant and totaled 2 inspections. As a result of a recent RI-ISI update that removed some conservative PRA modeling assumptions, this system is no longer safety significant. As such, the classification and treatment requirements of this action for this system are appropriate.
- the liquid radwaste (WL) system was identified at 2 units. There was no contribution to core damage and a less 1E-09/yr contribution to LERF. Thus, the classification and treatment criteria for this system is appropriate.

A number of general conclusions can also be drawn from the above review that supports the action as proposed. These include:

- Class 2, 3 and NNS service water are addressed by the requirement of this action to have a program in place (or assessment) that meets the intent of Generic Letter 89-13,
- A large portion of feedwater, main steam and EFW/AFW is addressed by the requirement of the action to have a program in place (or assessment) that meets the intent of Generic Letter 89-08 and the requirement to include the portion of the system from the steam generators to the break exclusion region within Category A,
- A large portion of the RHR and LPSI systems as well as portions of the HPSI system is addressed by the action's requirement to include applicable portions of the decay heat removal function,
- A number of systems (or subsystems) are pressurized due to connection to inventory sources (e.g. RWST, CST, VCT), are alarmed, as well as experience the same operating pressure during normal service as they do during during accident conditions. Thus, their failure is more likely to occur and be detected (e.g Tech Spec action statements) during normal operation.
- Several of the applications cited in this whitepaper are what is known in the PRA discipline as relative risk applications. That is, an item's risk (safety) significance is a function of the relative risk significance of all other items modeled in the PRA. These conservatisms in the PRA analysis/model can portray some items (e.g. Class 2/3/NNS) artificially high. Subsequently, some of these applications have undergone updates which are showing as more conservatisms are removed from the PRA analysis/model, the population of high safety significant items are migrating away from Class 2, 3 and NNS items and towards the category A criteria as defined by this action.

In 2001, the USNRC approved an exemption request for the South Texas Project. In their submittal, South Texas Project requested that they be exempted from numerous special treatment requirements. As part of their review of this request, the USNRC developed guidance in assessing SSCs not explicitly modeled in the plant PRA as well as SSCs that are not important from a CDF/LERF perspective but may be important in terms of other risk metrics or conditions (Reference 27). This guidance consists of a set of 10 specific additional considerations. Six of

these considerations pertain to SSCs not modeled in the PRA, including other modes of operation and four pertain to other risk metrics/conditions.

Table 3 provides a listing of these additional considerations and discusses how this action addresses these considerations. It should be noted the USNRC guidance specifically states that qualitative evaluations are sufficient to address these additional considerations. While a qualitative evaluation is certainly sufficient, many of the insights supporting this action are from quantitative assessments of the impact of pressure boundary component failures (i.e. consequences of failure). Therefore, although not explicitly modeled in a number of PRAs, the information summarized in Table 2 provides exactly the type of evaluations requested by Reference 27 and in many cases exceeds that which was requested via Reference 27.

Finally, several additional requirements are imposed by this action that are beyond that currently required by the ASME code. These include:

- programs to address component reliability in response to Generic Letter 88-01 (NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping, Reference 28), Generic Letter 89-08 (Erosion/Corrosion Induced Pipe Wall Thinning, Reference 29) and Generic Letter 89-13 (Service Water System Problems Affecting Safety-Related Equipment, Reference 30).
- implementation of an operating experience review program that meets the intent of NUREG-0737 (Reference 31). This program requires that plant-specific procedures be in place that ensure operating information pertinent to plant safety, originating from internal as well as external sources (e.g. INPO, NRC, vendors, other plants) be supplied to appropriate plant staff, incorporated into staff training programs and be assessed as to its impact on plant safety.
- the owner shall have conducted a plant-specific evaluation and implemented changes, as applicable, that meet the intent of Generic Letter 88-20 (Individual Plant Examination for Severe Accident Vulnerabilities – 10CFR50.54(f) [Reference 24]. This shall include an assessment by a second party (e.g. regulatory body, peer review panel) that concludes that the PRA (IPE) approach is technically sound and capable of identifying plant-specific vulnerabilities.
- the owner shall have in place a change control process that meets the intent of 10CFR50.59 (Changes, Tests and Experiments) [Reference 32].

As described in Generic Letter 88-20, the purpose of this plant-specific evaluation is:

1. to develop an appreciation of severe accident behavior,
2. to understand the most likely severe accident sequences that could occur at its plant,
3. to gain a more quantitative understanding of the overall probabilities of core damage and fission product releases, and
4. if necessary, to reduce the overall probabilities of core damage and fission product releases by modifying, where appropriate, hardware and procedures that would help prevent or mitigate severe accidents

As such, Generic Letter 88-20 requires licensees to implement cost-effective plant improvements to eliminate plant-specific vulnerabilities as identified by the IPE process. In addition, licensee were required to identify these improvements and provide them to the NRC (regulator) as stated in Appendix 4 to the generic letter as follows:

"A list of the potential improvements, if any (including equipment changes as well as changes in maintenance, operating and emergency procedures, surveillance, staffing, and training programs) that have been selected for implementation and a schedule for their implementation or that are already implemented. Include a discussion of the anticipated benefit as well as any drawbacks."

These requirements assure that any plant-specific vulnerabilities have been identified and proper actions (e.g. hardware changes) implemented. If there are any specific inspections that were implemented in response to the IPE evaluation, then the proposed action requires these inspections to be continued. This assures that any plant-specific issues that can be effectively addressed via an inspection program continue to be addressed in a cost-effective manner, regardless of the item's category (e.g. category B inspections).

The 10CFR50.59 process assures that changes made to the plant in the future will be conducted in a controlled manner and that changes will not be made that invalidate the above conclusions. Specifically, 10CFR50.59 requires that plant changes meet a set of requirements so that they do not:

(i) Result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the final safety analysis report (as updated);

(ii) Result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component (SSC) important to safety previously evaluated in the final safety analysis report (as updated);

(iii) Result in more than a minimal increase in the consequences of an accident previously evaluated in the final safety analysis report (as updated);

(iv) Result in more than a minimal increase in the consequences of a malfunction of an SSC important to safety previously evaluated in the final safety analysis report (as updated);

(v) Create a possibility for an accident of a different type than any previously evaluated in the final safety analysis report (as updated);

(vi) Create a possibility for a malfunction of an SSC important to safety with a different result than any previously evaluated in the final safety analysis report (as updated);

(vii) Result in a design basis limit for a fission product barrier as described in the FSAR (as updated) being exceeded or altered; or

(viii) Result in a departure from a method of evaluation described in the FSAR (as updated) used in establishing the design bases or in the safety analyses.

Thus, the proposed code case assures that category B items are appropriately assessed and cost-effective actions have been implemented to resolve any plant-specific issues and therefore do not need to be re-classified as category A items per this action.

Element 2 - Inservice Inspection Requirements

Definition: Items categorized as Category A shall meet the inspection requirements of IWB or IWC, as applicable, with the exception of examination categories B-F, B-J, C-F-1 and C-F-2.

Ten percent of the Category A items that belong to examination categories B-F, B-J, C-F-1 and C-F-2 shall be subjected to NDE inservice inspection. This ten percent sample shall be determined by evaluating each item's susceptibility to the degradation mechanism listed in Table 3 of the action and include the following:

- Each item selected, shall be subjected to non-destructive (i.e. volumetric) examination,
- Volumetric shall not be limited to only ultrasonic.
- Inspections shall be allocated equally among systems to the extent practical, and each system shall individually meet the following requirements:
  - Inspection shall be required for each degradation mechanism and degradation mechanism combination (e.g. thermal fatigue and IGSCC) identified,
  - For the reactor coolant pressure boundary, at least two thirds of the inspections shall be located inside the first isolation valve (i.e. closer to the RPV, consequence of component failure would be a LOCA),
  - For that portion of the reactor coolant pressure boundary that penetrates containment, if applicable, a representative inspection size shall be conducted,
  - For feedwater connections to steam generators in pressurized water reactors, an assessment shall be made as to the susceptibility to thermal fatigue and action taken (e.g. inservice inspection), if applicable,
  - Inspections shall be repeated in subsequent inspection intervals to the extent practical,
  - Inspections may be selected and scheduled to minimize worker exposure, scaffolding and other concerns provided the above requirements are met.
  - Augmented inspections may be credited towards the inspection population. No more than one half of the inspection population may be augmented inspections.

In lieu of the above inspection requirements, an approved risk-informed inservice inspection program (i.e. number and type of inspections) may be used for Category A items, provided Category B items that were used to justify a reduction in Category A inspections below 10 percent, if applicable, continue to be inspected.

Category B items do not require inservice inspection other than pressure testing at a frequency of at least once per inspection interval.

Technical Basis: A review and analysis of the results of RI-ISI plant-specific applications has been conducted. These applications total forty nine units and cover Class 1 only applications, Class 1 and 2 applications, as well as several full scope applications (i.e. Class 1, 2, 3 & some NNS). Attachment 1 provides a summary listing of RI-ISI applications and status. In addition, a review of

the requirements of the applicable ASME code cases (i.e. N560, N577 and N578) has been conducted. In addition, an extension to the RI-ISI methodology to address break exclusion regions (BER, aka high energy piping, HELB) which result in additional/augmented inspections due to USNRC regulation was reviewed for applicability and the criteria herein reflects this information.

Results of these evaluations provide the following conclusions:

- For Class 1 systems, except for augmented programs due to IGSCC in BWRs, results are at or below 10%.
- Class 2 piping tends to be at 0.1 to 2.0 percent range,
- Class 2 inspections are dominated by the shutdown heat removal function encompassing 40 to 60 percent of inspections, depending upon where the system boundaries are defined (e.g. LPSI, RWST),
- Augmented programs (e.g. FAC, localize corrosion) also cover a large portion of the RI-ISI identified Class 2/3/NNS inspections,
- BER – 0 to 12 % for PWR/BWR but at 10% it is still higher than the existing 7.5% code requirement for Class 2 components and therefore an increase over existing code requirements.
- The decay removal function (from the reactor to the first components, suction and discharge, outside containment capable of remote isolation) is included because during shutdown evolutions this equipment can be important (e.g. no S/G available).
- This action continues the existing requirements on Class 3 and NNS items. These requirements are currently allowed and are being implemented by plants not implementing RI-ISI programs. In addition, of the 43 follow-on RI-ISI applications that have been approved by USNRC, none have required inspections of Class 3/NNS components.
- Although some RI-ISI applications have shown feedwater connections to steam generators as low safety significant, because of the functions supported (e.g. secondary heat removal, power generation), the potential for degradation (e.g. thermal fatigue) and the consequences of specific failures (e.g. break exclusion regions), it is felt prudent to classify the portion of the feedwater system (> 4 NPS) from the steam generators to the outer containment isolation valve/boundary restraint as category A.
- Section 1(b) of the action requires that the plant have augmented programs in place to monitor and/or inspect for localized corrosion (e.g. MIC), flow accelerated corrosion (FAC) and IGSCC in BWRs, as applicable. This is another step that assures that component reliability for category B systems and subsystems will continue to be maintained.
- Augmented inspections may be credited towards the inspection population, where appropriate. For example, a number of BWRs have inspection requirements in response to Generic Letter 88-01. A portion of these may be credited towards the ten percent target.
- With respect to augmented programs, some risk-based evaluations have concluded that additional inspections beyond augmented programs are not necessary. However, for defense in depth and component reliability purposes this action requires additional inspections thereby providing a substantive ongoing assessment of the condition of the pressure boundary function.

In addition, the proposed action allows owners to utilized a previously approved RI-ISI application. This will allow utilities that were able to justify sample sizes less than 10% to continue to use these

programs, provided a number of conditions are met. If a plant chooses to use the previously approved program, all relevant conditions and requirements of the RI-ISI program must continue to be met. Examples include confirming the scope of the programs are the same, if inspections in category B items were used to reduce inspections on category A items, then the category B exams need to continued (e.g. a service water exam replacing a RCS exam or a Class 2 SIS exam replacing a Class 1 SIS exam).

Element 3 – Pre-service Inspection Requirements

Definition: Items classified as category A shall be subjected to 100% pre-service inspection. The inspection volumes, techniques and procedures shall be in accordance with Table 2 (i.e. thermal fatigue, SCC, cavitation, FAC, LC, etc.) of the proposed action. As an alternative, pre-service inspection may be conducted to the Section XI requirements originally used.

Items classified as Category B do not required pre-service inspection.

Technical Basis: Two options are provided to the user. The first is to use the RI-ISI volumes/requirements which are based upon an "inspection for cause" philosophy and have been shown to provide adequate levels of quality and safety. The second option is to use existing deterministic Section XI volumes/requirements which have been used successfully over the last twenty plus years and also provide adequate levels of quality and safety. The purpose of providing this option is to respond to emergent issues that may arise during non-planned plant/system outage evolutions.

Element 4 – Requirements for Repair/Replacement Activities

Definition: Items classified as Category A shall meet all of the requirements of IWA-1400(n), IWA-4000, and IWA-6210(e) as stipulated in the proposed action. In addition, RRM activities shall be reviewed against Table 3 of the proposed action to assure that the RRM activity does not introduce any of the degradation mechanisms listed in Table 3 or that plant-specific programs/procedures are in place to confirm component reliability is maintained.

Items classified as Category B shall meet the reduced requirements as stipulated in section 4 (Structural Integrity Requirements) of the proposed action. In addition, RRM activities shall be reviewed against Table 3 of the proposed action to assure that the RRM activity does not introduce any of the degradation mechanisms listed in Table 3 or that plant-specific programs/procedures are in place to confirm component reliability is maintained.

Technical Basis: Code Case N662 was developed for trial use to define the repair/replacement requirements for high safety significant (HSS) items versus low safety significant (LSS) items in risk-informed repair/replacement activities. HSS and LSS were to be defined elsewhere (e.g. N660). This action replaces the HSS and LSS designations with Category A and B designations, respectively. As discussed above, the basis for this categorization is presented in Element 1. From a practical perspective, there is no difference between HSS and category A or LSS and category B other than nomenclature and the more robust basis for this action as compared to trial use code case N660. As such, the basis for the reduced treatment requirements for category B items is identical to that for LSS items in code case 662. Finally, this action imposes an additional requirement upon the owner to confirm that degradation mechanisms listed in Table 3 of the proposed action are not introduced into the plant and/or that plant-specific programs/procedures are in place to confirm component reliability is maintained.

DESCRIPTION OF THE CHANGE

The action can be summarized as impacting four areas as they pertain to assuring pressure boundary integrity. That is,

- defining alternative classification criteria,
- defining alternative inservice inspection requirements based upon the component's classification,
- defining alternative pre-service inspection requirements based upon the component's classification,
- defining alternative requirements for repair/replacement activities based upon the component's classification.

CONCLUSION

Risk-informed technology has matured substantially over the past thirty years, and in particular, its application to pressure boundary integrity. As a result of pilot plant applications, code case development and application, and a number of follow-on plant applications, the knowledge base of this technology has grown substantially. These developments have placed the code in a position to define the next evolution in pressure boundary integrity management. Thus, we are now at a point where the identification and application of a blended and integrated set of risk-informed criteria and treatment requirements for pressure boundary components is available.

The criteria in the proposed action identifies those components (i.e. category A items) that should continue to receive "special treatment" while providing for reduced burden on less important components (i.e. category B items). Importantly, this action also provides requirements for assuring continued reliability of the category B items.

Table 1
RI-ISI Implementation Status

Plant	Submittal	Approval	Method	Scope
ANO, U1	6-3-1999	8-25-1999	N560	B-J, excluding socket welds
ANO, U2	9-30-1997	12-29-1998	N578	Class 1, 2, 3 & NNS
Braidwood, U1	10-16-2000	2-20-2002	N578	Class 1 & 2
Braidwood, U2	10-16-2000	2-20-2002	N578	Class 1 & 2
Browns Ferry, U2	12-20-1999	1-12-2001	N577	Class 1, 2, 3 & NNS
Browns Ferry, U3	4-23-1999	2-11-200	N577	Class 1, 2, 3 & NNS
Brunswick, U1	4-20-2001	11-28-2001	N578	Class 1
Brunswick, U2	4-20-2001	11-28-2001	N578	Class 1
Byron, U1	10-16-2000		N578	Class 1 & 2
Byron, U2	10-16-2000		N578	Class 1 & 2
Callaway	2-16-2001	1-30-2002	N578	Class 1 & 2
Clinton	10-15-2001	4-8-2002	N578	Class 1 & 2
Columbia	8-16-2000	3-9-2001	N560	B-J, excluding socket welds
Comanche Peak, U1	2-15-2001	9-28-2001	N578	Class 1 & 2
Comanche Peak, U2	2-15-2001	9-28-2001	N578	Class 1 & 2
Diablo Canyon, U1	2-16-2001	11-8-2001	N578	Class 1 & 2
Diablo Canyon, U2	2-16-2001	11-8-2001	N578	Class 1 & 2
Dresden, U1		9-5-2002	N578	Class 1 & 2
Dresden, U2		9-5-2002	N578	Class 1 & 2
Fermi	4-30-2001	9-10-2001	N578	Class 1
FitzPatrick	10-13-1999	9-12-2000	N578	Class 1, 2, 3 & NNS
Indian Pt, U3	2-5-2002	2-4-2003	N578	Class 1
LaSalle, U1	5-18-2001	12-27-2001	N578	Class 1 & 2
LaSalle, U2	5-18-2001	12-27-2002	N578	Class 1 & 2
McGuire, U1	6-26-2001	6-12-2002	N578	Class 1 & 2
McGuire, U2	6-26-2001	6-12-2002	N578	Class 1 & 2
Millstone, U3 *				Class 1, 2, 3 & NNS
Millstone, U3	7-25-2000	3-12-2002	N577	Class 1
Monticello	12-18-2001	7-24-2002	N578	Class 1 & 2
Nine Mile Pt, U1	2-22-2002	9-4-2002	N578	Class 1 & 2
Nine Mile Pt, U2	10-16-2000	5-31-2001	N578	Class 1 & 2
North Anna, U1	4-26-2001	9-18-2001	N577	Class 1
North Anna, U2	4-26-2001	9-18-2001	N577	Class 1
Perry	2-12-2001	10-17-2001	N578	Class 1
Pilgrim	12-27-2000	5-2-2001	N578	Class 1
Quad Cities, U1	11-30-2000	2-5-2002	N578	Class 1 & 2
Quad Cities, U2	11-30-2000	2-5-2002	N578	Class 1 & 2
Seabrook	3-16-2001	2-7-2002	N578	Class 1
Sequoyah, U1		10-19-2001	N577	Class 1 & 2
Sequoyah, U2		10-19-2001	N577	Class 1 & 2
South Texas, U1	12-30-1999	9-11-2000	N560	B-J, excluding socket welds
South Texas, U2	12-30-1999	9-11-2000	N560	B-J, excluding socket welds
South Texas, U1	2-27-2001	3-5-2002	N578	Class 1 sockets & Class 2
South Texas, U2	2-27-2001	3-5-2002	N578	Class 1 sockets & Class 2
Surry, U1		12-16-1998	N577	Class 1, 2, 3 & NNS
Surry, U2	4-27-2000	1-26-2001	N577	Class 1
Turkey Pt, U3	1-19-2000	11-30-2000	N577	Class 1
Vermont Yankee		11-9-1998	N560	B-J, excluding socket welds

Watts Bar	5-21-2001	1-24-2002	N577	Class 1 & 2
Wolf Creek	2-15-2001	12-13-2001	N578	Class 1 & 2

* - Millstone, Unit 3 was the reference plant for WCAP-14572, Revision 0.

Table 2
Summary of RI-ISI Results

Plant	Method	Scope	Results (1) (2)		
			Class 2	Class 3	NNS
ANO, U2	N578	Class 1, 2, 3 & NNS	CSS – 4 - RC4 LPSI – 19 - RC4 EFW – 3 - RC4 MFW – 6 - RC5 (TF) SWS **	SWS**	SWS** - 2
Braidwood, U1	N578	Class 1 & 2		Zero	Zero
Braidwood, U2	N578	Class 1 & 2		Zero	Zero
Browns Ferry, U2	N577	Class 1, 2, 3 & NNS	MS – 2 (TF) RCIC – 1 (TF) HPCI – 2 (TF)	Zero	Zero
Browns Ferry, U3	N577	Class 1, 2, 3 & NNS	HPCI – 2 – LSS (D in D) FW – FAC MS – FAC MS – 2 LSS (D in D) RCIC – 1 – LSS (op act) RHR – 4 – LSS (op act)	Zero	Zero
Byron, U1	N578	Class 1 & 2		Zero	Zero
Byron, U2	N578	Class 1 & 2		Zero	Zero
Callaway	N578	Class 1 & 2	FW – 2 - RC5 (TF) CVCS – 9 - RC4 SWS – 1 - RC5 (MIC) RHR – 44 - RC4	Zero	Zero
Clinton	N578	Class 1 & 2	RH – 9 RC3 (FAC) RH – 1 RC5 (FAC)	Zero	Zero
Comanche Peak, U1	N578	Class 1 & 2	SIS – 11 - RC4 RHR – 24 - RC4 CSS – 1 - RC4 FW – 1 - RC5 (TF)	Zero	Zero
Comanche Peak, U2	N578	Class 1 & 2	SIS – 11 - RC4 RHR – 25 - RC4 CSS – 2 - RC4	Zero	Zero

Plant	Method	Scope	Results (1) (2)		
			Class 2	Class 3	NNS
			FW – 1 - RC5 (TF)		
Diablo Canyon, U1	N578	Class 1 & 2	CVCS – 2 - RC4 SIS – 6 - RC4 RHR – 3 - RC2 (TF) RHR – 18 - RC4 RWST – 5 - RC4 CCW – 2 - RC4 FW – 3 - RC5 (TF)	Zero	Zero
Diablo Canyon, U2	N578	Class 1 & 2	CVCS – 2 - RC4 SIS – 7 - RC4 RHR – 3 - RC2 (TF) RHR – 18 - RC4 RWST – 5 - RC4 CCW – 2 - RC4 FW – 3 - RC5 (TF)	Zero	Zero
Dresden, U1	N578	Class 1 & 2		Zero	Zero
Dresden, U2	N578	Class 1 & 2		Zero	Zero
FitzPatrick	N578	Class 1, 2, 3 & NNS	CS – 1 – RC5 (IGSCC+) HPCI – 2 - RC5 (TF) RHR – 5 - RC4	ESW – 1 - RC2 (Cav)	0
LaSalle, U1	N578	Class 1 & 2		Zero	Zero
LaSalle, U2	N578	Class 1 & 2		Zero	Zero
McGuire, U1	N578	Class 1 & 2	CSS – 4 (LSS) CSSV – 8 (LSS) CVCS – 40 RC – 1 RH – 2 (LSS) SI - 13 WL – 5 (LSS)	Zero	Zero
McGuire, U2	N578	Class 1 & 2	CSS – 4 (LSS) CSSV – 8 (LSS) CVCS – 35 RC – 1 RH – 2 (LSS) SI – 11 WL – 5 (LSS)	Zero	Zero

Plant	Method	Scope	Results (1)(2)		
			Class 2	Class 3	NNS
Millstone, U3 *		Class 1, 2, 3 & NNS	RWST – 1 ($Prob_f$<E-8) QSS – 2 ($Prob_f$<E-8) FW – 4 ($Prob_f$<E-8) FW – 4 (S/G nozzles) SIL – 5 (SDC?) SIH – 4 (RWST head?) Recirc – 1 (not in 3.4-14) CVCS – 6 (not in 3.4-14)	FW – 1 ($Prob_f$<E-8) CCW – 5 (not in 3.4-14) SW** – 18	Zero
Monticello	N578	Class 1 & 2	RCIC – 2 - RC4 RCIC – 3 - RC5 (TF) HPCI – 3 - RC4 HPCI – 4 – RC5 (TF)	Zero	Zero
Nine Mile Pt, U1	N578	Class 1 & 2	CTN – 2 EC - 1	Zero	Zero
Nine Mile Pt, U2	N578	Class 1 & 2	CSL – 1 - RC4 ICS – 2 - RC4 ICS – 1 RC5 - (TF) RHS – 4 - RC4 RHS – 23 – RC5 (TF)	Zero	Zero
Quad Cities, U1	N578	Class 1 & 2		Zero	Zero
Quad Cities, U2	N578	Class 1 & 2		Zero	Zero
Sequoyah, U1	N577	Class 1 & 2	BD – 12 (FAC) CSS – 3 (LSS) FW – 8 – (FAC only?) MS – 1 (delta risk) RH – 8 (LSS) SI – 12 (???)	Zero	Zero
Sequoyah, U2	N577	Class 1 & 2	BD – 12 (FAC) CSS – 3 (LSS) FW – 8 (FAC only?) RH – 6 (LSS, 4 delta risk) SI – 12 (???)	Zero	Zero
South Texas, U1	N578	Class 1 & 2	AFW – 3 – RC5 (TF) FW – 2 – RC5 – (TF) RH – 2 – RC5 – (TF)	Zero	Zero
South Texas, U2	N578	Class 1 & 2	AFW – 3 – RC5 (TF)	Zero	Zero

Plant	Method	Scope	Results (1) (2)		
			Class 2	Class 3	NNS
			FW – 2 – RC5 – (TF) RH – 2 – RC5 – (TF)		
Surry, U1	N577	Class 1, 2, 3 & NNS	AFW – 5 (CST head?) BD – 3 (App J?) CH – 1 (RX trip) CS – 2 (not in 3.6-17) ECC – 1 (RWST head) HHI – 15 (RWST suctn?) LHI – 7 (RWST suctn?) MS – 2 (testing) RH – 4 (SDC) RS – 2 (recirc)	AFW – 3 (CST head?) CC - 13 (CONT) SW** – 5 VS – 2 (chilled water)	AS – 2 (FAC) BD - 3 (App J) FW – 7 (BER, FAC, LMFW)
Watts Bar	N577	Class 1 & 2	AF – 8 (FAC) BD – 8 (FAC) CSS – 3 (LSS) FW – 5 (FAC) RH – 6 (LSS) SI – 13 (???)	Zero	Zero
Wolf Creek	N578	Class 1 & 2	FW – 2 - RC5 (TF) CVCS – 9 - RC4 RHR – 3 - RC2 (TF) RHR – 44 – RC4	Zero	Zero

Footnotes:

(1) System identifiers are as follows:

AFW – auxiliary feedwater
BD – blowdown
CH – charging
CSL – low pressure core spray
CSSV – containment ventilation cooling water
CVCS – chemical & volume control
ECC – emergency core cooling
ESW - essential service water
HHI – high head injection
HPSI – high pressure safety injection
AS – auxiliary steam
CC, CCW – component cooling water
CS – core spray
CSS – containment spray PWR
CTN – containment spray-BWR-1
EC – emergency condenser-BWR-1
EFW – emergency feedwater
FW – feedwater
HPCI – high pressure core injection
ICS – reactor core isolation cooling

LHI – low head injection	LPSI – low pressure safety injection
MFW – main feedwater	MS – main steam
QSS – quench spray	RCIC – reactor core isolation cooling
RC – Reactor Coolant	Recirc – sump recirculation
RH, RHR, RHS – residual heat removal	RS - ????
RWST – reactor water storage tank	SIL – low head safety injection
SIS – safety injection	SWS – service water
VS – chilled water	WL – liquid radwaste

(2) The information in the Class 2, 3 and NNS column meets the following format:

system – number of inspections – risk category, if known, reason for risk significance (e.g. type of degradation, consequence). Two examples are as flows:

"HPCI – 2 - RC5 (TF)" represents:

system – high pressure core injection,

number of inspections – two inspections were identified by the RI-ISI process,

risk category – medium risk per code case N560 and N578 RI-ISI methodology,

reason for risk significance – these locations were identified as potentially susceptible to thermal fatigue

"RH – 4 (SDC)" represents:

system – residual heat removal,

number of inspections – four inspections were identified by the RI-ISI process,

reason for risk significance – these locations were identified as part of the shutdown cooling flowpath and therefore would be classified as category A per this action.

"MS – 2 LSS (D in D)" represents:

system – main steam,

number of inspections – two inspections were identified by the RI-ISI process,

reason for risk significance – these locations were identified as low safety significance. They were randomly selected and added to the inspection population in response to an USNRC request for additional information.

* - Millstone, Unit 3 was the reference plant for WCAP-14572, Revision 0.

** - Should be adequately addressed by the GL 89-13 program requirement

TABLE 3
Additional Considerations

No.	Consideration	Response
1	Failure of the component will significantly increase the frequency of an initiating event, including those initiating events originally screened out in the PRA.	This action does not change the function of any SSC, therefore its failure will not increase the frequency of any initiating event. In addition, SSC reliability is expected to be maintained or increase as a result of this action. RRM activities on category B SSCs will be assessed for susceptibility to degradation as defined in Table 3 of the proposed action. Thus, likelihood of failure is expected to be maintained or decreased.
2	Failure of the component will compromise the integrity of the reactor coolant pressure boundary.	Requirements for reactor coolant pressure boundary components are unchanged. In addition, SSC reliability may actually increased as RRM activities for category B SSCs will be assessed for susceptibility to degradation as defined in Table 3 of the proposed action.
3	Failure of the component will fail a safety function, including components that are assumed to be inherently reliable (e.g., piping and tanks) and those that may not be explicitly modeled in the PRA (e.g., room cooling systems, and instrumentation and control systems). For example, it is expected for PWRs that a sufficiently robust categorization process would categorize high energy Class 2 or 3 piping of the main steam and feedwater systems as HSS.	Applicable portions of the feedwater and main steam systems in PWRs as well as BWRs are classified as category A (i.e. HSS) per the proposed.
4	The component supports important operator actions required to mitigate an accident.	Treatment requirements (i.e. ISI, PSI and RRM) for category A SSCs are commensurate with the components' significance and reflect the lessons learned from various

No.	Consideration	Response
		risk-informed applications. Although treatment requirements are reduced for category B components, structural integrity will continue to be maintained. Additionally, component reliability may actually increase for some category B components as RRM activities will be assessed for susceptibility to degradation per Table 3 of the proposed action.
5	Failure of the component will result in failure of safety significant components (e.g., through spatial interactions).	This action does not change the function of any SSC, therefore the impact of its failure will not change. In addition, SSC reliability is expected to be maintained or increase as a result of this action. RRM activities on category B SSCs will be assessed for susceptibility to degradation as defined in Table 3 of the proposed action. Thus, likelihood of failure is expected to be maintained or decreased.
6	Failure of the component will impact the plant's capability to reach and/or maintain safe shutdown conditions.	This action does not change the function of any SSC, therefore the impact of its failure will not change. In addition, SSC reliability is expected to be maintained or increase as a result of this action. RRM activities on category B SSCs will be assessed for susceptibility to degradation as defined in Table 3 of the proposed action. Thus, likelihood of failure is expected to be maintained or decreased.
7	The component is a part of a system that acts as a barrier to fission product release during severe accidents.	This action does not change the requirements for fuel, fuel cladding, the RCPB, SDC, BER or significant portions of the feedwater system. Structural integrity for category B components will continue to be maintained. In addition, component reliability may actually increase as RRM

No.	Consideration	Response
		activities on category B components will be assessed for susceptibility to degradation per Table 3 of the proposed action.
8	The component is depended upon in the Emergency Operating Procedures or the Severe Accident Management Guidelines and provides a significant mitigating or diagnosis function.	Structural integrity for category B components will be maintained. In addition, component reliability may actually increase as RRM activities on category B components will be assessed for susceptibility to degradation per Table 3 of the proposed action.
9	Failure of the component will result in unintentional releases of radioactive material even in the absence of severe accident conditions.	Structural integrity for category B components will be maintained. In addition, component reliability may actually increase as RRM activities on category B components will be assessed for susceptibility to degradation per Table 3 of the proposed action.
10	The component is relied upon to control or to mitigate the consequences of transients and accidents significant to plant safety or reliability.	Structural integrity for category B components will be maintained. In addition, component reliability may actually increase as RRM activities on category B components will be assessed for susceptibility to degradation per Table 3 of the proposed action.

Case N-XXX

Minimum Examination Coverage Requirements for Class 1 and Class 2 Piping Welds

Section XI, Division 1

Inquiry: What are the minimum examination coverage requirements for Class 1 (IWB-2500) and Class 2 (IWC-2500) piping welds?

Reply: It is the opinion of the Committee that the minimum examination coverage requirements for Class 1 and Class 2 piping welds may be determined by applying the partial examination coverage evaluation process defined in Table 1. This process may be used on Class 3and non-nuclear safety (NNS) welds required to be examined as part of a risk-informed inservice inspection program for piping.

Table 1

Partial Examination Coverage Evaluation Process

Damage Mechanism	Process Decision Point	If Decision Point is "Yes"	If Decision Point is "No"	Risk Characterization	
				Method A	Method B
FAC	Requirements governed by plant FAC program. No further action required.			Region 1A	Category 1 Category 3 Category 5
WH + other DM VF (assumed)	(a) Is water hammer and/or vibratory fatigue still applicable?	• correct design deficiency • re-risk rank system without water hammer and/or vibratory fatigue	• re-risk rank system without water hammer and/or vibratory fatigue		
	(b) Is the examination still required?	• assess conservatism in damage mechanism analysis	• no further action required		
	(c) Is the examination still required? Re-risk ranking may be required after assessing conservatism in the damage mechanism analysis.	• see decision point (d)	• no further action required		
	(d) Is an alternate inspection location available with a comparable or higher failure potential?	• conduct examination • no further action required	• partition by applicable damage mechanism as shown below		
TASCS TT	(e) Is the inspection location on a horizontal run to a steam generator or BWR vessel, including feedwater nozzle?	• see decision point (f)	• see decision point (g)	Region 1A Region 3 Non RI-ISI Exam	Category 2 Category 5 Non RI-ISI Exam
	(f) Was the pipe side of the weld, pipe side heat affected zone and pipe side counterbore captured?	• document exam limitation and coverage achieved and verify examination performed to the extent practical, including best effort for component side • no further action required	• volume of primary interest not sufficiently examined • essentially 100% coverage required		
	(g) Is the inspection location a pipe to component weld? Includes pipe to pumps, valves, nozzles and branch connections.	• see decision point (h)	• see decision point (i)		

Table 1

Partial Examination Coverage Evaluation Process

Damage Mechanism	Process Decision Point	If Decision Point is "Yes"	If Decision Point is "No"	Risk Characterization	
				Method A	Method B
	(h) Was the pipe side of the weld, pipe side heat affected zone and pipe side counterbore captured?	• document exam limitation and coverage achieved and verify examination performed to the extent practical, including best effort for component side • no further action required	• see decision point (j)		
	(i) Is the counterbore located within ½" of the weld fusion line?	• volume of primary interest not sufficiently examined • essentially 100% coverage required	• document exam limitation and coverage achieved and verify examination performed to the extent practical • no further action required	Region 1A Region 3 Non RI-ISI Exam (Cont'd)	Category 2 Category 5 Non RI-ISI Exam (Cont'd)
	(j) Is the counterbore located within ½" of the weld fusion line?	• volume of primary interest not sufficiently examined • essentially 100% coverage required	• document exam limitation and coverage achieved and verify examination performed to the extent practical, including best effort for component side • no further action required		
IGSCC (BWR)	Requirements governed by owner controlled program. No further action required.				
IGSCC (PWR) TGSCC PWSCC	(k) Is the inspection location a pipe or safe end to nozzle weld?	• see decision point (l)	• see decision point (o)		
	(l) Is Alloy 600, 182 or 82 present? Includes fitting, weld and/or buttering.	• partial coverage (i.e., ≤ 90%) is not acceptable • essentially 100% coverage required	• see decision point (m)		

Table 1

Partial Examination Coverage Evaluation Process

Damage Mechanism	Process Decision Point	If Decision Point is "Yes"	If Decision Point is "No"	Risk Characterization	
				Method A	Method B
	(m) Was the pipe side of the weld, pipe side heat affected zone and pipe side counterbore captured?	• document exam limitation and coverage achieved and verify examination performed to the extent practical, including best effort for component side • no further action required	• see decision point (n)		
	(n) Is the counterbore located within ½" of the weld fusion line?	• volume of primary interest not sufficiently examined • essentially 100% coverage required	• document exam limitation and coverage achieved and verify examination performed to the extent practical, including best effort for component side • no further action required		
	(o) Is the inspection location a pipe to component weld? Includes pipe to pumps, valves and branch connections.	• see decision point (p)	• see decision point (s)		
	(p) Is the ferrite content ≥ 8% and carbon content < 0.05%?	• see decision point (q)	• partial coverage (i.e., ≤ 90%) is not acceptable • essentially 100% coverage required	Region 1A Region 3 Non RI-ISI Exam (Cont'd)	Category 2 Category 5 Non RI-ISI Exam (Cont'd)
	(q) Was the pipe side of the weld, pipe side heat affected zone and pipe side counterbore captured?	• document exam limitation and coverage achieved and verify examination performed to the extent practical, including best effort for component side • no further action required	• see decision point (r)		

Table 1

Partial Examination Coverage Evaluation Process

Damage Mechanism	Process Decision Point	If Decision Point is "Yes"	If Decision Point is "No"	Risk Characterization	
				Method A	Method B
	(r) Is the counterbore located within ½" of the weld fusion line?	• volume of primary interest not sufficiently examined • essentially 100% coverage required	• document exam limitation and coverage achieved and verify examination performed to the extent practical, including best effort for component side • no further action required		
	(s) Is the counterbore located within ½" of the weld fusion line?	• volume of primary interest not sufficiently examined • essentially 100% coverage required	• document exam limitation and coverage achieved and verify examination performed to the extent practical • no further action required		
ECSCC	(t) Are chlorides or other contaminants present at the inspection location? Determined by investigating source of postulated attack (e.g., leakage) and conducting swipes, etc.	• implement corrective actions • document findings • no further action required	• document findings • no further action required		
MIC PIT	Requirements governed by owner controlled program. No further action required.				
CC	(u) in the course of preparation				
E-C	(v) Is the coverage adequate to identify wastage at the inspection location?	• document exam limitation and coverage achieved and verify examination performed to the extent practical • no further action required	• insufficient coverage • essentially 100% coverage required		
No DM Identified	(w) Is the inspection location a pipe to component weld? Includes pipe to pumps, valves, nozzles and branch connections.	• see decision point (x)	• see decision point (y)	Region 1B, 2	Category 4

Table 1

Partial Examination Coverage Evaluation Process

Damage Mechanism	Process Decision Point	If Decision Point is "Yes"	If Decision Point is "No"	Risk Characterization	
				Method A	Method B
	(x) Was the pipe side of the weld, pipe side heat affected zone and pipe side counterbore captured?	• document exam limitation and coverage achieved and verify examination performed to the extent practical, including best effort for component side • no further action required	• see decision point (z)		
	(y) Is the counterbore located within ½" of the weld fusion line?	• volume of primary interest not sufficiently examined • essentially 100% coverage required	• document exam limitation and coverage achieved and verify examination performed to the extent practical • no further action required		
	(z) Is the counterbore located within ½" of the weld fusion line?	• volume of primary interest not sufficiently examined • essentially 100% coverage required	• document exam limitation and coverage achieved and verify examination performed to the extent practical, including best effort for component side • no further action required		