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PLANT-SPECIFIC APPLICABILITY OF THE TRANSITION BREAK SIZE

A. INTRODUCTION

Purpose

This regulatory guide (RG) describes an approach that is acceptable to the U.S. Nuclear Regulatory Commission (NRC) for demonstrating that the generic transition break size (TBS) specified in Part 50, “Domestic Licensing of Production and Utilization Facilities,” in Title 10 of the *Code of Federal Regulations* (10 CFR) (Ref. 1), section 50.46a, “Alternative acceptance criteria for emergency core cooling systems for light-water nuclear power reactors,” is applicable to the facility of an entity that is seeking to implement 10 CFR 50.46a. The entity submits the initial demonstration with the application to implement the rule as required in 10 CFR 50.46a(c)(1)(i) or 10 CFR 50.46a(c)(2),¹ as applicable. This evaluation is needed because the analyses conducted to determine the loss-of-coolant accident (LOCA) frequencies in the technical basis for 10 CFR 50.46a were not bounding. Therefore, plant-specific information is needed to confirm that the analyses conducted in the rule’s technical basis are applicable to the entity applying to use 10 CFR 50.46a.

Regulations in 10 CFR 50.46a(c)(1)(i), 10 CFR 50.46a(c)(2), and 10 CFR 50.46a(d)(4) also require entities to demonstrate the continued applicability of the TBS after adopting the initial proposed plant modifications, including when making additional plant modifications enabled by the rule. This guidance provides an acceptable approach to demonstrate the continued applicability of the TBS. These demonstrations are either submitted for NRC review under 10 CFR 50.46a(h)(2) or performed as part of an NRC-approved risk-informed evaluation process under 10 CFR 50.46a(h)(1). This guide credits a variety of programs that many entities will already have implemented (e.g., aging management and in-service inspection) to simplify the process of confirming the TBS. Licensees should indicate in their application which existing NRC-approved programs are being credited to demonstrate applicability of the TBS. No additional justification by the entity or review by the NRC is expected regarding programs or their outputs to address one of the technical topics in this guide unless the scope of the NRC-approval does not encompass its proposed use in demonstrating the applicability of the TBS.

¹ Under 10 CFR 50.46a(c)(1) or 10 CFR 50.46a(c)(2), entities can justify an alternate TBS suitable for their design. This guide provides implementation guidance for the TBS established in the rule and does not provide a method for determining an alternate TBS permissible under, but not established in the rule.

This RG is being issued in draft form to involve the public in the development of regulatory guidance in this area. It has not received final staff review or approval and does not represent an NRC final staff position. Public comments are being solicited on this DG and its associated regulatory analysis. Comments should be accompanied by appropriate supporting data. Comments may be submitted through the Federal rulemaking website, <http://www.regulations.gov>, by searching for draft regulatory guide DG-1428. Alternatively, comments may be submitted to Office of the Secretary, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, ATTN: Rulemakings and Adjudications Staff. Comments must be submitted by the date indicated in the *Federal Register* notice.

Electronic copies of this DG, previous versions of DGs, and other recently issued guides are available through the NRC’s public website under the Regulatory Guides document collection of the NRC Library at <https://nrc.gov/reading-rm/doc-collections/reg-guides>. The DG is also available through the NRC’s Agencywide Documents Access and Management System (ADAMS) at <http://www.nrc.gov/reading-rm/adams.html>, under Accession No. ML24341A154. The regulatory analysis is associated with a rulemaking and may be found in ADAMS under Accession No. ML26181A099.

Applicability

This RG applies to holders of an operating license under 10 CFR Part 50 that was issued before December 31, 2015, hereafter referred to as “existing plants.” The RG also applies to holders of a construction permit or an operating license under 10 CFR Part 50 issued after December 31, 2015, and holders of a combined license, standard design approval, or manufacturing license under 10 CFR Part 52, “Licenses, Certifications, and Approvals for Nuclear Power Plants” (Ref. 2), whose reactor design is demonstrated under 10 CFR 50.46a(c)(2) to be similar to the designs of boiling-water reactors (BWRs) and pressurized-water reactors (PWRs) licensed under 10 CFR Part 50 before December 31, 2015. These facilities are hereafter collectively referred to as “new plants.” The guidance applicable to existing plants differs from that applicable to new plants. This RG does not apply to a facility for which the certification required under 10 CFR 50.82(a)(1) or 10 CFR 52.110(a)(1) has been submitted to permanently cease operations. Further, this guidance is only applicable for demonstrating that breaks in the primary loop piping and reactor coolant pressure boundary components that are larger than the TBS have an extremely low likelihood of occurrence and that the TBS in 10 CFR 50.46a is applicable.

Applicable Regulations

- 10 CFR Part 50 provides regulations for licensing production and utilization facilities.
 - 10 CFR 50.46, “Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors,” governs the design requirements for the emergency core cooling system (ECCS) and criteria to demonstrate that the calculated cooling performance of the ECCS following postulated LOCAs is adequate.
 - 10 CFR 50.46a provides a voluntary alternative to 10 CFR 50.46 that allows licensees to recategorize LOCAs above a TBS as beyond-design-basis accidents, permitting the use of best estimate modeling and realistic assumptions when assessing ECCS performance.
 - 10 CFR 50.55a, “Code and standards,” incorporates by reference certain American Society of Mechanical Engineers (ASME), Institute for Electrical and Electronics Engineers, NRC, and Electric Power Research Institute (EPRI) documents and identifies any conditions associated with their approval by the NRC.
 - 10 CFR 50.82(a)(1)(i) requires licensees to provide written certification to the NRC within 30 days from making the determination to permanently cease operations.
 - 10 CFR 50.90, “Application for amendment of license, construction permit, or early site permit,” requires that, whenever a holder of a license (including a construction permit and an operating license under 10 CFR Part 50, as well as an early site permit, combined license, or manufacturing license under 10 CFR Part 52) wishes to amend the license or permit, it must file an application for a license amendment with the Commission to fully describe the desired changes.
 - 10 CFR Part 50, Appendix A, “General Design Criteria for Nuclear Power Plants,” General Design Criterion (GDC) 4, “Environmental and dynamic effects design bases,” requires systems, structures, and components (SSCs) important to safety to be designed to

accommodate environmental conditions associated with operation and postulated accidents and to be protected against dynamic effects.

- GDC 30, “Quality of reactor coolant pressure boundary,” requires reactor coolant pressure boundary (RCPB) components to be designed, fabricated, erected, and tested to the highest quality standards practical and to provide means for detecting and identifying the location of the source of reactor coolant leakage.
- 10 CFR Part 52 governs the issuance of early site permits, standard design certifications, combined licenses, standard design approvals, and manufacturing licenses for nuclear power facilities.
 - 10 CFR 52.110(a)(1) requires licensees to provide written certification to the NRC within 30 days from making the determination to permanently cease operations.
- 10 CFR Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants” (Ref. 3), governs the issuance of renewed operating licenses and renewed combined licenses for nuclear power plants.

Related Guidance

- NUREG-1829, “Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process,” issued April 2008 (Ref. 4), describes the development of generic LOCA frequency estimates of passive system failure as a function of break size for both BWR and PWR plants.
- NUREG-1903, “Seismic Considerations for the Transition Break Size,” issued February 2008 (Ref. 5), assesses the likelihood that rare seismic events would induce primary system failures larger than the postulated TBS.
- NUREG-1801, Revision 2, “Generic Aging Lessons Learned (GALL) Report,” issued December 2010 (GALL Report) (Ref. 6), contains the staff’s generic evaluation of the existing plant aging management programs (AMPs) and documents the technical basis for determining where existing programs are adequate without modification and where the applicant seeking license renewal (LR) should augment them for the period of extended operation.
- NUREG-1800, Revision 2, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants—Final Report,” issued December 2010 (SRP-LR) (Ref. 7), provides staff guidance for the safety review of applications to renew nuclear power plant licenses in accordance with 10 CFR Part 54.
- NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report,” issued July 2017 (GALL-SLR Report) (Ref. 8), contains the staff’s generic evaluation of plant AMPs and establish the technical basis for their adequacy for subsequent license renewal (SLR), in addition to recommendations on specific areas for which existing AMPs should be augmented for SLR.
- NUREG-2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants—Final Report,” issued July 2017 (SRP-SLR) (Ref. 9), provides staff

guidance for the safety review of applications to renew the initial renewed operating license in accordance with 10 CFR Part 54.

- RG 1.45, Revision 1, “Guidance on Monitoring and Responding to Reactor Coolant System Leakage” (Ref. 10), describes acceptable methods for selecting reactor coolant leakage detection systems, monitoring for leakage, and responding to leakage.
- NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition” (SRP) (Ref. 11), provides staff guidance for performing safety reviews of construction permit or operating license applications under 10 CFR Part 50 and early site permit, design certification, combined license, standard design approval, or manufacturing license applications under 10 CFR Part 52.
- RG 1.245, “Preparing Probabilistic Fracture Mechanics Submittals” (Ref. 12), describes a framework to develop the contents of a licensing submittal that the NRC considers acceptable when performing probabilistic fracture mechanics (PFM) analyses in support of regulatory applications.
- RG 1.147, “Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1” (Ref. 13), lists the ASME Boiler and Pressure Vessel Code (ASME Code), 2023, (Ref. 14), Section XI, Code Cases that the NRC has approved for use as voluntary alternatives to the mandatory ASME Code provisions incorporated by reference into 10 CFR Part 50.
- Draft Regulatory Guide (DG)-1426 (proposed new RG 1.225), “An Approach for a Risk-Informed Evaluation Process Supporting Alternative Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Reactors” (Ref. 15), provides an approach to demonstrate that proposed facility changes will satisfy the requirements of 10 CFR 50.46a(h).
- RG 1.200, “Acceptability of Probabilistic Risk Assessment Results for Risk-Informed Activities” (Ref. 16), describes an approach for determining whether the technical adequacy of the probabilistic risk assessment (PRA), in total or the parts that are used to support an application, is sufficient to provide confidence in the results, such that the PRA can be used in regulatory decision-making for light-water reactors (LWRs).
- RG 1.174, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis” (Ref. 17), describes a risk-informed approach using PRA for evaluating plant-specific changes to the licensing basis.

Purpose of Regulatory Guides

The NRC issues RGs to describe methods that are acceptable to the staff for implementing specific parts of the agency’s regulations, to explain techniques that the staff uses in evaluating specific issues or postulated events, and to describe information that the staff needs in its review of applications for permits and licenses. Regulatory guides are not NRC regulations and compliance with them is not required. Methods and solutions that differ from those set forth in RGs are acceptable if the applicant provides sufficient basis and information for the NRC staff to verify that the alternative methods comply with the applicable NRC regulations.

Paperwork Reduction Act

This RG provides voluntary guidance for implementing the mandatory information collections in 10 CFR Parts 50 and 52 and 10 CFR 50.55a that are subject to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.). These information collections were approved by the Office of Management and Budget (OMB), under control numbers 3150-0011, 3150-0151, and 3150-0264, respectively. Send comments regarding this information collection to the FOIA, Library, and Information Collections Branch, Office of the Chief Information Officer, Mail Stop: T6-A10M, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001 or by e-mail to Infocollects.Resource@nrc.gov, and to the OMB reviewer at: OMB Office of Information and Regulatory Affairs (3150-0011 and 3150-0151), Attn: Desk Officer for the Nuclear Regulatory Commission, 725 17th Street, NW, Washington, DC 20503.

Public Protection Notification

The NRC may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the document requesting or requiring the collection displays a currently valid OMB control number.

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B. DISCUSSION

Reason for Issuance

The issuance of this guidance provides entities² with one acceptable method for demonstrating that the generic TBS specified in 10 CFR 50.46a is applicable to a specific facility, that an adequate leak detection program has been established, and that proposed plant changes do not invalidate the TBS. In addition, this guidance provides a method to verify that new degradation mechanisms do not emerge that would invalidate the frequency assumptions for the TBS, by performing inspections of an NRC-approved, risk-informed sample of the similar metal piping circumferential welds in a PWR and the circumferential welds in a BWR that are classified as Category A welds with the highest failure potential.

The regulations for an application to use 10 CFR 50.46a are in 10 CFR 50.46a(c)(1)(i) for existing plants and 10 CFR 50.46a(c)(2) for new plants. These regulations require an entity to conduct an initial evaluation to demonstrate the applicability of the TBS and submit the evaluation in a request for NRC review and approval. If the NRC approves the entity's application to use 10 CFR 50.46a, then 10 CFR 50.46a(d)(4) requires a subsequent evaluation to demonstrate the continued applicability of the TBS before the entity can adopt proposed plant modifications. Each subsequent evaluation by an entity other than a design certification applicant or a holder of a manufacturing license can be performed as part of an NRC-approved self-approval process, which would be submitted in accordance with 10 CFR 50.46a(c)(1)(v)(C) and then implemented subject to the conditions in 10 CFR 50.46a(h)(1). Alternatively, the entity submits this evaluation in a request for NRC review and approval under 10 CFR 50.46a(h)(2) before implementing the intended plant changes. In 10 CFR 50.46a(c)(1)(vii), the NRC requires that the leak detection program in place at the facility satisfy the criteria in 10 CFR 50.46a(d)(2). Inspections required by 10 CFR 50.46a are stipulated in 10 CFR 50.46a(b)(3), while the results of initial inspections are reported as part of the application in 10 CFR 50.46a(c)(1)(ii). Subsequent inspections during operation are to be performed and evaluated as required by 10 CFR 50.46a(d)(5) and then reported in accordance with 10 CFR 50.46a(j)(5).

On May 23, 2025, President Donald J. Trump signed Executive Order (E.O.) 14300, "Ordering the Reform of the Nuclear Regulatory Commission" (Ref. 18). Section 5, "Reforming and Modernizing the NRC's Regulations," requires the NRC to undertake a review and wholesale revision of its regulations and guidance documents as guided by the policies set forth in section 2 of the E.O. Additionally, as part of the NRC's overarching review of all of its regulations, the agency identified a number of additional changes to the NRC's regulations that will improve the efficiency and efficacy of its licensing process that are also included in this RG.

Background

The NRC has amended its regulations and updated guidance to facilitate the use of LWR fuel containing uranium enriched to greater than 5.0 weight percent uranium-235. In Staff Requirements Memorandum (SRM)-SECY-21-0109, "Staff Requirements—SECY-21-0109—Rulemaking Plan on Use of Increased Enrichment of Conventional and Accident Tolerant Fuel Designs for Light-Water Reactors," dated March 16, 2022 (Ref. 19), the Commission directed the staff to address and analyze "fuel fragmentation, relocation, and dispersal issues relevant to fuels of higher enrichment and burnup levels." Fuel fragmentation and relocation are necessary precursors to ductile-failure-induced fuel dispersal, so

2 "Entity" means an applicant for or a holder of a construction permit, operating license, combined license, standard design approval, or manufacturing license, or an applicant for a standard design certification rule (including such applicant after NRC issuance of a final standard design certification rule).

they are often discussed together. While addressing SRM-SECY-21-0109 in the development of 10 CFR 50.46a, the NRC realized that dispersal poses a challenge that the other two phenomena do not, in that fuel fragmentation and relocation into the ballooned region of the fuel rod could be addressed within the existing regulatory framework. However, regulatory action was needed to address and analyze fuel dispersal.

As part of a prior 10 CFR 50.46a rulemaking effort that did not become final (Ref. 20), the NRC communicated the generic technical basis for the TBS in NUREG-1829 and NUREG-1903. NUREG-1829 developed LOCA frequency estimates of passive system failure as a function of break size for both BWR and PWR plants and considered normal operational loading and transients expected over a 60-year plant life. NUREG-1903 assessed the likelihood that rare seismic events would induce primary system failures larger than the postulated TBS.

NUREG-1829—Generic LOCA Frequency Estimates

The elicitation efforts described in NUREG-1829 focused on developing generic average BWR and PWR LOCA frequency estimates for the commercial fleet and the uncertainty bounds on these generic estimates, rather than on bounding values associated with one or two plants. This approach is consistent with prior studies (Ref. 21 and 22) that did not consider plant-specific differences in developing LOCA frequencies for use in PRA modeling. Consequently, the elicitation panelists considered broad differences among plants related to important variables (e.g., plant system, material, geometry, degradation mechanism, loading, mitigation, and maintenance) in determining the generic LOCA frequencies and especially the estimated uncertainty bounds. The broad differences in these important variables principally affect passive system failure, and, in general, sufficient commonality among plants exists to enable a meaningful generic assessment.

The NUREG-1829 study also relied on several implicit and explicit assumptions regarding plant design and operation and regulatory oversight. For example, the study assumed that plant construction and operation comply with all applicable codes and standards required by the regulations and technical specifications. The study also assumed that regulatory oversight policies and procedures will continue to be used to identify and mitigate risk associated with entities having deficient safety practices. Another important assumption was that current regulatory oversight practices will continue to evaluate aging management and mitigation strategies to reasonably ensure that future plant operation and maintenance have equivalent or decreased risk. A related assumption inherent in this elicitation was that all future plant operating characteristics will be essentially consistent with past operating practice. The study did not consider the effects of operating profile changes because of the large uncertainty surrounding possible operational changes and the potentially wide-ranging ramifications of significant plant changes on the historical LOCA frequencies supported by operating experience.

The elicitation primarily considered the effects of primary system stresses resulting from normal plant operational cycles and transients expected over a 60-year lifetime. The NRC chose this focus because these types of stresses are the most generic, and they have been the basis for historical LOCA frequencies that are currently used in most internal-event PRAs. Consequently, NUREG-1829 does not consider rare event loading from seismic, severe water hammer, and other sources because of the strong dependency that plant-specific factors have on these stresses. However, the NRC conducted separate research, as documented in NUREG-1903, to assess the potential impact of seismic loading on the break frequency versus break size relationship.

The NRC conducted additional analyses to reaffirm the applicability of the TBS, considering the operating history that has occurred, and other research and knowledge gained since the early 2000s (Ref. 23). Specifically, the NRC:

- considered the impact of recent operational experience and its relevance to the TBS
- conducted a detailed PFM study to verify the NUREG-1829 base case frequencies, which were used to anchor the LOCA frequencies
- performed an internal and external elicitation to identify possible scenarios not considered, or underestimated, in NUREG-1829 that could result in primary pressure boundary breaches that are larger than the TBS in both PWRs and BWRs
- completed a database study to estimate whether worldwide operational experience would modify the LOCA frequencies

NUREG-1903—Seismic Effects on Generic Failure Frequencies

The NUREG-1903 study evaluated seismic effects on failure frequencies associated with (1) direct failure of flawed and unflawed piping and (2) piping failure caused indirectly through the failure of other structural components and supports. An example is a hypothetical snubber failure in which applied loading on the piping system during a seismic event exceeds the design loading such that the piping ultimately fails. This study did not perform bounding seismic analyses to encompass all potential plant-specific variations, including site-to-site variability in the seismic hazard. Rather, the study evaluated the seismic effects associated with the TBS using case studies, an evaluation of operating experience, and insights from seismic PRAs. The two principal study objectives were to (1) examine the likelihood and conditions that would result in the prediction of seismically induced breaks in piping systems with inside diameters that are greater than the TBS and (2) develop analytical procedures that can be used to perform case-specific seismic analyses. This study investigated the effect of seismic events occurring with a frequency of 10^{-5} per year (/yr) or less, which is the LOCA frequency assumed for breaks smaller than the TBS (i.e., breaks above the TBS would be even less likely).

The study demonstrated generically that the seismically induced failure frequency in unflawed large-diameter (i.e., inside diameter greater than the TBS) piping systems is significantly less than 10^{-5} /yr, the metric for establishing the TBS. Additionally, for the cases reported in NUREG-1903, large flaws are required for failure induced by seismic events having an annual probability of exceedance of 10^{-5} /yr and 10^{-6} /yr. Coupled with other mitigative aspects that the study did not consider, the frequency of pipe breaks larger than the TBS are likely to be less than 10^{-5} /yr. The analysis of indirect failure frequencies updated prior plant-specific studies conducted by Lawrence Livermore National Laboratory (LLNL) using most current seismic hazard and group motion information (Ref. 5). For the two plant-specific indirect failure scenarios evaluated, the probabilities of indirect failures of large RCPB piping systems are much less than 10^{-5} /yr.

To reaffirm the applicability of NUREG-1903, the NRC revisited the results of the original NUREG-1903 studies by applying the same analytical methodologies to seismic hazard information available since NUREG-1903's publication in 2008 (Ref. 24). For the unflawed piping failure case, the study confirmed that the probabilities of exceedance corresponding to 1 percent probability of failure are all below the TBS frequency criterion of 10^{-5} /yr. For the flawed piping failure case, given the existing insight that the critical flaws associated with stresses corresponding to 10^{-5} /yr and 10^{-6} /yr probability of exceedance seismic events are generally large, the probability of pipe breaks larger than the TBS are likely to be less than 10^{-5} per year.

Need for Plant-Specific Confirmation

Unique plant attributes associated with operational or seismic loading may result in higher plant-specific LOCA frequencies than the generic (non-bounding) assessments described above. The Commission recognized this potential in the prior 10 CFR 50.46a rulemaking and directed the staff to require entities “to justify that the generic results in the revised NUREG-1829...are applicable to their individual plants.”³ Additionally, the Commission directed the staff to “develop regulatory guidance that will provide a method for establishing this justification.” For this reason, this guide provides methods for entities to confirm that the TBS is appropriate for their site-specific characteristics. If the licensee for an existing plant cannot demonstrate applicability of the TBS, then the licensee would need to develop and justify a plant-specific TBS to use 10 CFR 50.46a.

While neither NUREG-1829 nor NUREG-1903 explicitly considered new plants, the NRC staff recognizes that these plants use many of the same materials, have similar environments, are expected to have reasonably similar stresses, and follow similar mitigation and maintenance practices as the existing BWR and PWR plants. These new plants also adhere to the same regulatory framework as the existing plants, and they were designed according to similar requirements in ASME Code, Section III, and follow similar requirements in ASME Code, Section XI, during operation. Therefore, this RG uses consistent principles for demonstrating the plant-specific applicability of the TBS for both new and existing plants. However, additional considerations are pertinent for new plants to evaluate potential differences that neither NUREG-1829 nor NUREG-1903 considered to demonstrate that the generic TBS is applicable to their plants. If this applicability cannot be demonstrated, then the entity will need to determine a plant-specific TBS to use 10 CFR 50.46a as required by 10 CFR 50.46a(c)(2).

General Considerations

The TBS size for PWR plants is the diameter corresponding to the largest cross-sectional flow area of the RCPB piping, excluding the main loop piping (i.e., hot leg, cold leg, and crossover leg) in PWRs. The TBS size for BWR plants is the diameter corresponding to the largest cross-sectional flow area of either the feedwater or the residual heat removal piping inside primary containment. The piping systems with inner diameters that are greater than the TBS, breaks in which could be treated as beyond-design-basis accidents under 10 CFR 50.46a, are hereafter referred to collectively as the primary loop piping (PLP). Plant-specific evaluations, therefore, only need to consider attributes that would increase the likelihood of breaks in the PLP and in RCPB structural components of similar or greater size, such that failures of these components could cause a break that is bigger than the TBS. Such non-piping RCPB components include pumps, valves, the reactor pressure vessel, pressurizer, steam generators, and the associated nozzles connecting these components to the PLP.

This guide credits a variety of NRC-approved programs that many entities will already have implemented (e.g., aging management, in-service inspection) to simplify the process of confirming the TBS. No additional justification by the entity or review by the NRC is expected regarding these programs or their outputs when their application is credited to address one of the technical topics in this guide unless the scope of the NRC-approval does not encompass its proposed use in demonstrating the applicability of the TBS.

3 SRM-SECY-07-0082, “Staff Requirements—SECY-07-0082—Rulemaking to Make Risk-Informed Changes to Loss-of-Coolant Accident Technical Requirements; 10 CFR 50.46a, ‘Alternative Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors,’” dated August 10, 2007 (Ref. 25).

B.1 NUREG-1829 Applicability

The expert elicitation described in NUREG-1829 developed generic BWR and PWR LOCA frequencies by considering the effects and relationships among the important variables that principally affect passive system failure. These variables include the materials, fabrication methods, service environment, applied loading, age-related degradation mechanisms, geometry and configuration, and maintenance and mitigation associated with the system. The most common degradation mechanisms that can cause defects to develop in the subject PLP systems and RCPB components are related to fatigue (thermal, mechanical, or thermal-mechanical) and stress corrosion cracking (SCC).⁴ Additionally, thermal aging and radiation embrittlement are degradation mechanisms that, in certain materials, cause the material strength to increase while the ductility and toughness decrease.

The expert elicitation considered the effects of broad differences among the various reactor classes and designs (i.e., Combustion Engineering, Babcock and Wilcox, Westinghouse, and General Electric). The elicitation also assumed that the design and fabrication, inspection and mitigation, and repair and replacement requirements comply with all applicable codes and standards required by regulations and technical specifications. In addition, the elicitation assumed that any unregulated aging management and mitigation strategies comply with existing common industry practices.

The existing regulatory requirements provide reasonable assurance that an entity's design, fabrication, repair, and replacement activities comply with required regulations such that no additional justification is necessary to demonstrate their applicability of the NUREG-1829 results unless plant-specific deviations exist that may lead to increases in the plant-specific LOCA frequencies. In this case, the effects of any such deviations should be considered. These mechanisms, however, do not typically induce flaws but should be considered in the evaluation to determine the applicability of the TBS. Figure 1 shows the analyses acceptable to demonstrate the plant-specific applicability of NUREG-1829. While the following sections describe several options to demonstrate applicability, entities can leverage existing programs and/or requirements to demonstrate applicability of the NUREG-1829 results. These items include the following:

1. Aging management programs that have been approved under LR or SLR (no new justification or NRC review needed)
2. Leak detection programs that conform to RG 1.45, Revision 1 (Ref. 10) (no new justification or NRC review needed)
3. Leak-before-break (LBB) methods that have been approved by the NRC⁵ (no new justification or NRC review needed)
4. An inspection program that provides assurance that unexpected degradation mechanisms that could invalidate the basis for the TBS will be identified (plant-specific justification and NRC review needed, unless the NRC approves generic industry methods)

B.1.1 Aging Management

As previously discussed, the TBS was based, in part, on the NUREG-1829 estimates of the LOCA frequencies associated with long-lived, primary pressure boundary, passive SSCs. The elicitation that formed the basis for these generic estimates used certain assumptions related to the aging

4 Intergranular SCC and primary-water SCC are the most common SCC mechanisms in BWR and PWR RCPB systems.

5 The NRC has approved LBB for only PWRs. BWRs may find it advantageous to consider it for implementation of 10 CFR 50.46a as well as to enable other plant changes.

management of these SSCs. One fundamental assumption was that entities will continue to comply with their licensing basis throughout the period of plant operation. Additionally, the elicitation assumed that entities are implementing, and will continue to implement, an NRC-approved in-service inspection (ISI) program and AMPs appropriate for each relevant SSC. These assumptions were necessary in the elicitation to preclude consideration of the effects of significant plant-specific differences in the aging management of these SSCs so that generic results could be developed.

The elicitation further assumed that current regulatory oversight practices will continue to evaluate aging management and mitigation strategies to reasonably ensure that future plant operation and maintenance has equivalent or decreased risk. The NRC's process for issuing renewed operating licenses under 10 CFR Part 54 constitutes a regulatory oversight process for evaluating an entity's aging management and mitigation activities. Thus, an entity that has been issued a renewed license or a subsequently renewed license need not further demonstrate that its aging management practices are consistent with the assumptions used in developing the NUREG-1829 LOCA frequency estimates.

Additionally, an entity that has submitted its first LR application to the NRC need not further demonstrate that its aging management practices are consistent with the NUREG-1829 assumptions and has the option of either waiting until entering the LR period (i.e., operation from 40 years to 60 years) and adopting its approved AMPs before implementing 10 CFR 50.46a or adopting proposed AMPs that are applicable to the PLP or RCPB components before LR approval. If early adoption is chosen, the approved AMPs should be implemented upon final LR approval to rectify any differences between the proposed and approved AMPs.

Licensees for existing plants that have not applied for LR and entities with new plants should demonstrate that either existing programs or proposed enhancements to existing programs ensure a reliable and adequate aging management program for their PLP and RCPB components. One acceptable way of conducting this demonstration is for licensees to compare their existing programs for those PLP and RCPB components with those in the GALL or GALL-SLR Reports and justifying the acceptability of any associated deviations. These reports address the applicable inspection and mitigation activities associated with age-related degradation and describes applicable time-limited aging analysis to be performed on susceptible components during the LR and SLR periods. Further, these reports document the NRC staff's basis for determining which existing industry programs are adequate without modification and which existing programs should be augmented for LR or SLR.

Augmenting existing programs may be needed if the materials, fabrication methods, operating environments, loading conditions, or inspection programs are substantially different than in existing LWR plants, for which the GALL and GALL-SLR Reports were written. A careful evaluation of plant-specific operating experience to date and of similarly designed plants as well as a comparison with comparable LWR operating experience are essential components of any evaluation to either demonstrate adequacy of the existing aging management program or provide a basis for proposed augmented programs. New plants with little operating experience should also consider international operating experience for similarly designed plants.

B.1.2 Adequate Leak Detection

Adequate leak-detection capabilities provide additional assurance that the structural integrity of the RCPB is maintained. GDC 30 requires that entities provide the means for detecting and, to the extent practical, identifying the location of the source of RCPB leakage. Technical specification maximum limits on leakage are typically approximately 1 gallon per minute for existing PWRs and 5 gallons per minute for existing BWRs. These limits have been shown to provide sufficient margin against structural failure (Ref. 26).

RG 1.45 addresses the types of leakage, leakage separation procedures, methods for monitoring leakage and identifying its source, monitoring system performance, seismic qualification, and leakage management. The staff issued Revision 1 of RG 1.45 to incorporate progress in RCPB leakage detection technology; address the effects of reduced reactor coolant activity due to improved fuel integrity when using radiation monitoring to monitor leakage; and incorporate lessons learned from operating experience. Revision 1 also provides detailed guidance for timely detection and location of leaks, continuous monitoring, quantifying and trending leak rates, assessing safety significance of leakage, and specifying plant actions following confirmation of an adverse trend in the unidentified leak rate. The RG describes acceptable leakage detection systems and methods, using risk-informed and performance-based criteria to the extent practical. It retains the recommendations for monitoring sump level or flow, airborne particulate activity, and condensate flow rate from air coolers. It recommends other supplementary detection methods for use where and when appropriate.

One acceptable method for demonstrating adequate leak detection in a plant wishing to implement 10 CFR 50.46a is to adhere to the guidance in RG 1.45. If this approach is followed, any deviations from the RG 1.45 guidance (e.g., higher unidentified leakage flow rates) should be appropriately justified to demonstrate the objectives of RG 1.45 are achieved. Alternatively, an entity could describe the plant's leakage detection methods and demonstrate how these methods address both the GDC 30 requirements "for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage" and the 10 CFR 50.46a(c)(1)(vii) requirement that the facility's leak detection program satisfy the criteria in 10 CFR 50.46a(d)(2) to identify, monitor, and quantify leakage to ensure that adverse safety consequences do not result from leaking primary pressure boundary components that are larger than the TBS.

B.1.3 Plant Specific Analyses

The entity's evaluation should also demonstrate that the effects of each individual unique plant attribute or the combined effects of all unique plant attributes do not result in substantial increases in the NUREG-1829 generic LOCA frequency estimates. Important plant-specific attributes to consider are related to the materials and fabrication methods, applied loading, geometry and configuration, service environment, and maintenance and AMPs associated with the PLP and each RCPB component. Existing plants should largely be able to leverage existing analyses and programs in this evaluation while new LWR plants should more comprehensively assess differences between their plants and the existing BWR and PWR plants considered in the NUREG-1829 analysis.

Both existing and new plants can leverage an approved LBB evaluation of the PLP systems that can result in breaks greater than the TBS. Such an analysis addresses any plant-specific materials, geometries and configurations, and consideration of aging effects. Most importantly, plant-specific transient loading considerations (e.g., increased seismic loads due to loop isolation valves) are an essential feature of these analyses. Since an LBB evaluation is required to be updated if a plant change occurs that impacts the analyses or as part of a license renewal application (to demonstrate continued applicability through the period of extended operations), an entity planning to leverage their LBB submittal only needs to demonstrate that no further update is needed. If an update is needed, the evaluation should incorporate aging effects of materials within these systems over the entity's current license period. SRP Section 3.6.3, "Leak-Before-Break Evaluation Procedures," provides staff reviewer guidance for evaluating LBB evaluations and describes one acceptable method for conducting such analyses.

Both existing and new plants without an approved LBB evaluation for applicable PLP systems could choose to submit one as part of their application or perform and submit a PFM evaluation of these systems. An acceptable method is described in RG 1.245 and would enable entities to demonstrate that

the probability of rupture of the PLP systems is extremely low under conditions consistent with the design basis for the piping as required by GDC 4. For the purposes of a probabilistic analysis, the Commission subsequently defined an extremely low probability of rupture as “of the order of 10^{-6} per reactor year for PWR primary coolant loop piping when all pipe rupture locations are considered” (Ref. 27). This quantitative definition of extremely low probability of rupture is also appropriate for demonstrating the applicability of the TBS to the plant-specific PLP systems using a PFM evaluation. The PFM analysis should address the same plant-specific attributes as in an LBB submittal. The impacts of plant-specific inspections conducted under the entity’s ISI program or performed to satisfy the 10 CFR 50.46a(b)(3) requirements can be credited within the PFM analysis. Additionally, the analyses conducted must be for the whole piping system and not just the limiting location(s).

Alternatively, a new or existing plant could address plant-specific attributes associated with their PLP systems. Such an evaluation should address their materials; fabrication practices; loading sources, frequencies, and magnitudes; their PLP geometries and system configurations; and aging management. The evaluation should identify any unique aspects of these attributes compared to the generic considerations used in NUREG-1829 and assess the impacts of these differences on the NUREG-1829 LOCA frequencies and the applicability of the TBS. A careful consideration of significant loading transients from water hammer, seismic, or other larger transients as well as an evaluation of loading, geometry, and fabrication conditions that could lead to fatigue or SCC are important components of such an analysis.

Under 10 CFR 50.46a(c)(2), a new plant will also need to demonstrate that the failure frequency of LOCAs greater than the TBS in RCPB components is consistent with the frequencies of non-piping components reported in NUREG-1829. Such components include the reactor pressure vessel, pressurizer, steam generator, reactor coolant pumps, and any PLP valves in existing LWR plants. New plants will have some, or possibly all, of these components at sizes that could lead to a LOCA greater than the TBS and may also have additional components that should be considered. As with the alternative evaluation for the PLP systems described above, such an evaluation should address the materials; fabrication practices; loading sources, frequencies, and magnitudes; geometry and configuration; and aging management for each RCPB component. The evaluation should identify any unique aspects of these attributes compared to the generic considerations for RCPB components considered in NUREG-1829 and assess the impacts of these differences on the NUREG-1829 LOCA frequencies and the applicability of the TBS.

B.1.4 Inservice Inspection to Identify Degradation Mechanisms

The ISI requirements in 10 CFR 50.46a(b)(3) and 10 CFR 50.46a(d)(5) for the PLP systems provide another essential component for both existing and new plants to demonstrate that plant specific attributes and unknown degradation mechanisms will not invalidate the TBS applicability. For existing plants, an NRC-approved, risk-informed sampling of the similar metal piping circumferential welds in a PWR and the circumferential Category A welds (in accordance with BWRVIP-75-A, “BWR Vessel and Internals Project, Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules,” issued October 2005 (Ref. 28)) in a BWR is required before implementing 10 CFR 50.46a and in every subsequent ISI interval.

One acceptable approach would be for an entity to sample 10 percent of those applicable circumferential welds in the PLP with the highest failure potential. The NRC would also consider other plant-specific or fleet-wide inspection programs that provide assurance that the TBS remains applicable. Welds already included in augmented inspection programs (e.g., Code Case N-770, “Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material With or Without Application

of Listed Mitigation Activities,” December 4, 2020) (Ref. 29), should be excluded from this sample because they already have a plant-specific inspection program that is acceptable for demonstrating the low-likelihood of failures greater than the TBS in these welds.

In the case of welds with no observed degradation to date, the highest failure potential is based on the worst combination of high tensile stresses considering applied normal operational loading and transients, weld residual (e.g., weld process, weld parameters, repair welding), other fabrication stresses (e.g., cold springing, aggressive surface grinding), and most susceptible material properties (e.g., alloy composition and processing history) affecting both susceptibility to potential cracking mechanisms and fracture toughness if all other variables are the same. Material property considerations should address both the initial weld and base material properties (i.e., cracking susceptibility and fracture toughness) in conjunction with material property decreases due to thermal aging, if applicable.

An active degradation mechanism is not expected with new plants, so new plants should similarly identify the welds with the highest potential of failure in their PLP systems for welds that may not otherwise be part of an inspection program or may have sampling that is less than 10 percent of the population. For both new and existing plants, welds within the PLP inspection population that are already contained in the inspection program can be credited and will not require additional inspection before implementing 10 CFR 50.46a.

While the inspection sample required by 10 CFR 50.46a(b)(3) encompasses welds that have not experienced significant cracking thus far in service, the most likely degradation mechanisms causing any future degradation are fatigue or SCC. Normal operational transients may lead to environmentally assisted thermal fatigue in PLP and associated RCPB components (i.e., nozzles). EPRI MRP-146, “Material Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines,” issued September 2016 (Ref. 30), and EPRI MRP-192, “Material Reliability Program: Assessment of Residual Heat Removal Mixing Tee Thermal Fatigue in PWR Plants,” issued August 2012 (Ref. 31), provide guidance for mitigating fatigue impacts in PWR PLP piping systems, while BWRVIP-196, “BWR Vessel & Internals Project, Assessment of Mixing Tee Thermal Fatigue Susceptibility in BWR Plants,” issued November 2018 (Ref. 32), and BWRVIP-75-A provide inspection guidance for fatigue-sensitive locations in BWR PLP piping systems. This guidance may help identify other potentially fatigue-sensitive PLP circumferential weld locations in existing plants based on the accumulated operating experience. This guidance may also provide insights to help identify fatigue-sensitive locations in new plants. However, additional evaluation of the unique design, configuration, and loading requirements, along with a review of existing operating experience, will be needed for new plants to augment any insights based on existing plant operating experience.

Residual stresses are the most important loading source impacting SCC susceptibility. Those weld processes and fabrication procedures that result in high tensile stresses at the inside surface of the PLP component are a necessary precursor to initiate SCC. Excessive cold work (e.g., greater than 15 percent localized strain) or aggressive grinding on the inside piping diameter are particularly detrimental to the material’s inherent cracking resistance and can impart high local tensile stresses. Repair welds are also a common source of high tensile stresses. Inner diameter repair welds that have not been heat treated lead to the highest inner diameter tensile stresses (Ref. 33), but any repair weld having significant depth (e.g., greater than 10 percent of wall thickness) and length (e.g., greater than 25 percent of weld circumference) can both increase the inner diameter stresses and result in additional plastic straining of that material (Ref. 34).

BWRVIP-75-A also provides guidance for inspecting BWR stainless-steel welds susceptible to intergranular SCC while ASME Code Case N-770, as incorporated by reference in 10 CFR 50.55a with conditions, provides inspection requirements for PWR dissimilar metal welds susceptible to primary

water SCC. These documents may provide further insights for identifying additional circumferential PLP weld locations that may be most sensitive to SCC. Next, weld locations with the largest seismic, water hammer, or other transient loads may, depending on the material fracture toughness, result in the smallest critical flaw sizes before rupture. Such weld locations are prime candidates for risk-informed inspection sampling.

Note that many of the considerations in choosing a risk-informed inspection sample to meet the 10 CFR 50.46a(b)(3) inspection sampling requirements are also consistent with the rationale used in LBB and PFM analyses for selecting limiting locations within the PLP systems for analysis. These evaluations may be leveraged when identifying the ISI sample population to satisfy 10 CFR 50.46a(b)(3). Finally, ASME Code Case N-716, “Alternative Piping Classification and Examination Requirements,” January 21, 2020 (Ref. 35), as adopted in RG 1.147 (Ref. 13), is used to implement risk-informed ISI programs. Consider the attributes for selecting a risk-informed inspection sample discussed in Code Case N-716 when identifying the ISI sample population to satisfy 10 CFR 50.46a(b)(3) requirements. Welds that exist in augmented inspection programs (e.g., Code Case N-770) should be excluded from this requirement.

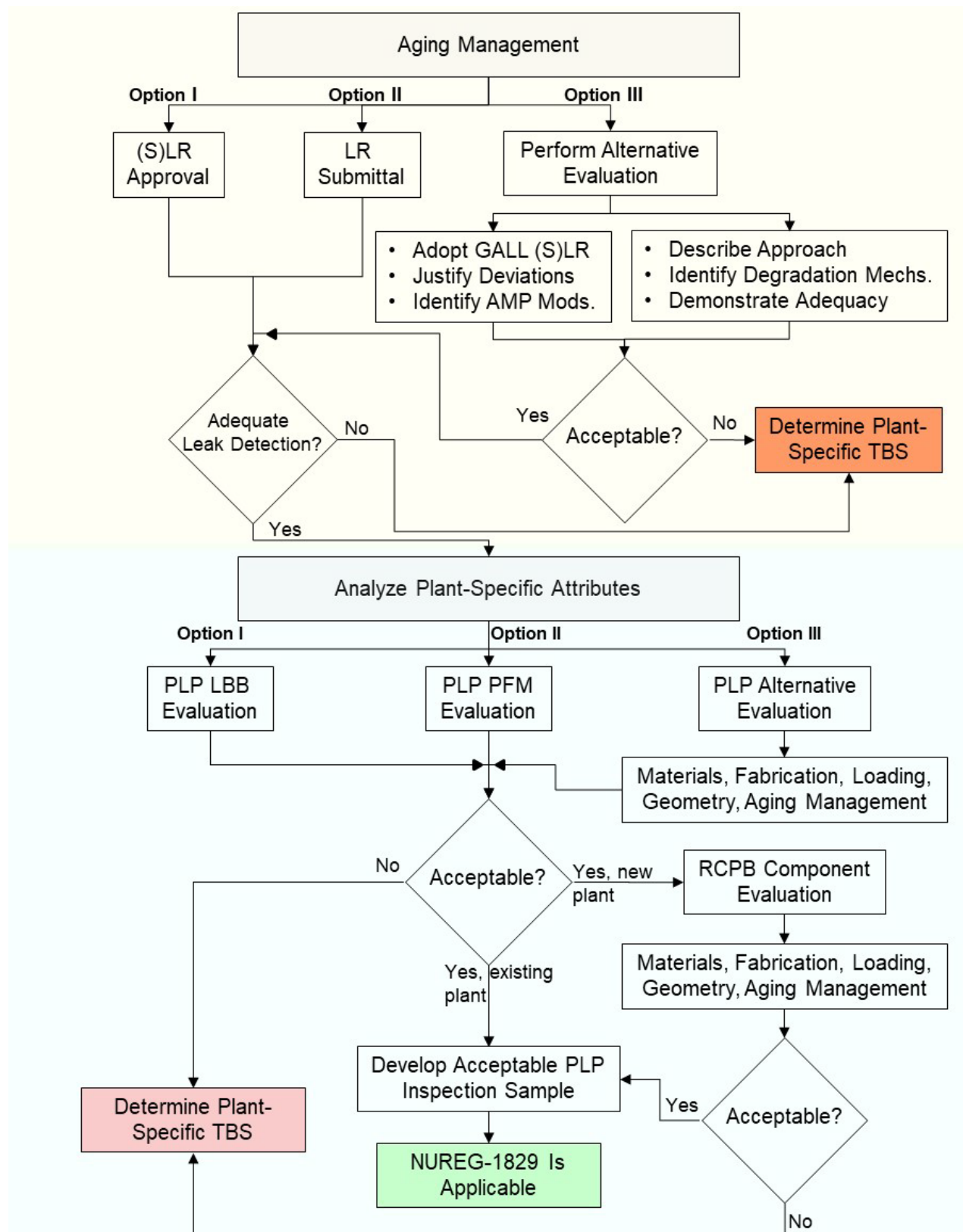


Figure 1. Evaluating plant-specific applicability of NUREG-1829

B.2 NUREG-1903 Applicability

The NRC staff revisited the results of the original NUREG-1903 studies by applying the same analytical methodologies used in NUREG-1903 to the updated seismic hazard information (Ref. 24). The results of the staff's updated seismic assessment confirm that seismic considerations are unlikely to affect selection of the TBS frequency criterion, but the staff recognizes that these non-bounding assessments may not account for any plant-specific seismic vulnerabilities. This fact is especially true for the cracked piping analyses conducted in NUREG-1903. While plant fragilities and uncracked piping behavior can be handled more generically, the assessment of cracked piping at the seismic limiting locations will be very plant specific due to design differences, loading differences, etc.

Figure 2 shows the analyses acceptable to demonstrate the plant-specific applicability of NUREG-1903. Entities seeking approval for the TBS can justify that NUREG-1903 is applicable through two main paths:

1. Inspection—if limiting locations are part of an ASME Code, Section XI, IWB-3500 program or an augmented program such as a risk-informed inspection program, and no flaws exceed the acceptance criteria, then no additional analysis is required to demonstrate applicability of the NUREG-1903 results. The NRC-approved inspection program described in section B.1.4 of this RG, whether plant-specific or fleet-wide, can be applied to meet this objective if the inspection scope covers the limiting locations and no further justification or NRC review is needed.
2. Analysis—if limiting locations are not part of an inspection program, then the entity will need to demonstrate analytically that its plant-specific seismic hazard and material properties are sufficient to justify the applicability of NUREG-1903 (i.e., that seismic contributions to the TBS-size LOCA frequency are less than the NUREG-1903 acceptance criteria).

B.2.1 Overview of NUREG-1903 Considerations

NUREG-1903 assessed the likelihood that rare seismic events induce primary system failures larger than the postulated TBS. In particular, the study evaluated direct and indirect failures of flawed and unflawed PLP systems and other RCPB components. This section of this guide summarizes the general scope, important assumptions, and approach used in the NUREG-1903 analysis and discusses its limitations to support the associated regulatory positions to demonstrate that the plant-specific risk of direct and indirect PLP and RCPB component failures is acceptably smaller than the risk associated with generic, passive system (i.e., non-seismic) LOCAs, as summarized in NUREG-1829.

The following considerations and knowledge of seismic events provided the framework for the NUREG-1903 analysis:

- Seismically induced LOCA frequencies are highly site and plant specific.
- Seismic hazard studies and approaches continue to evolve.
- Plant-specific information needed for the analysis (e.g., normal operating stresses, design seismic stresses, and material properties) was not available for every plant.
- Operating experience and prior PRA studies have determined that the most likely indirect PLP failures are caused by the failure of major reactor coolant system components or their supports (Ref. 36).

These considerations defined, in part, the scope and approach used in NUREG-1903. For example, they dictated the number and type of plants that were analyzed and the hazard information used in the NUREG-1903 study. Additionally, they allowed the analysis to be confined to the most risk-significant failure modes associated with the PLP.

All plant-specific piping design information used in NUREG-1903 was obtained from leak-before-break (LBB) analyses that were previously submitted by entities. These analyses provide the most comprehensive information on normal operating (i.e., pressure, bending, membrane, deadweight, thermal expansion) and safe-shutdown earthquake (SSE) seismic stresses for the pipe systems of interest. These analyses also provide other basic design information, such as pipe dimensions and material properties. The LBB analyses, however, are limited to PWR plants and to the specific PLP systems submitted for LBB approval. Similar information was not available for BWR plants.

Seismic stresses and seismically induced LOCA frequencies are proportional to the site-specific seismic hazard (Ref. 37). Furthermore, seismic hazard uncertainties are generally the dominant cause of uncertainties in seismic risk assessments (Ref. 5). NUREG-1903 used the revised LLNL seismic hazard curves and uniform hazard spectra (UHS) (Ref. 38) for its analyses. The LLNL results correspond to the 69 sites east of the Rocky Mountains and offered the most recent, comprehensive, and publicly available set of seismic hazard information at the time of the NUREG-1903 study. While the availability of the seismic hazard information from the LLNL study limited the NUREG-1903 analyses to only PWR plants located east of the Rocky Mountains, the general approach is equally applicable to any plant and site. Additionally, the generic insights obtained from the use of the LLNL seismic hazard information in NUREG-1903 remain valid, as they do not rely on the actual seismic hazard curves and UHS.

The NUREG-1903 report adopted the following approach to evaluate direct piping failures in PLP piping with diameters larger than the TBS. The hot leg, cold leg, and crossover legs are the only PWR PLP that is larger than the TBS. The evaluation of these legs combined deterministic and probabilistic elements and used sensitivity studies to address uncertainties. The evaluations included the following key elements for determining component stresses and material properties for each piping system evaluated:

- Stresses attributable to dead load, pressure, and thermal loading conditions were taken as point estimates from a database of industry LBB submittals.
- The evaluation of component-level seismic stresses for higher earthquake levels was based on the SSE stresses provided in the LBB database. However, the SSE stresses were corrected to account for ground motion and soil-structure interaction, as well as plant and piping system interaction caused by seismic loading.
- A structural response correction factor was developed to account for these known conservatisms in the design process. The correction factor was based on the seismic PRA scale-factor approach (Ref. 39).
- The structural response correction factor was then used to extrapolate the best estimate SSE stresses to higher earthquake levels as point estimates.
- The higher earthquake levels correspond to peak ground accelerations (PGAs) with annual exceedance probabilities of $10^{-5}/\text{yr}$ and $10^{-6}/\text{yr}$. These earthquake levels were determined using the LLNL mean PGA estimates and extrapolated, if necessary, for each plant-specific site evaluated.

- Material strength and load resistance parameters were based on mean material properties in the flawed-pipe evaluations. The unflawed-piping analysis used the allowable design stress intensity values, S_m , from Section II of the ASME Code to ensure consistency with the unflawed-piping failure criterion used in the analysis.
- The report considered material properties for a carbon steel that incorporated dynamic strain aging effects and for a stainless-steel submerged arc weld (SAW) that is susceptible to thermal aging. The analysis assumed that these materials are limiting.

After the component stresses and material properties were obtained for the piping system of interest, an elastic-plastic fracture mechanics (EPFM) evaluation based on the Z-factor approach (Ref. 40) was conducted to determine critical flaw sizes corresponding to failure due to seismic events with exceedance probabilities of $10^{-5}/\text{yr}$ and $10^{-6}/\text{yr}$. The Z-factor is the ratio of the failure stress predicted from a limit-load calculation to the failure stress predicted by an EPFM calculation. This approach is deemed a best estimate evaluation because representative, and not conservative, information was sought at each step.

The analysis of direct piping failures selected 26 PWRs to encompass representative operating, seismic, and total stresses; a variety of pipe and weld materials with varying toughness properties; and a range of seismic hazards. The study focused on PWRs located on rock sites (i.e., 24 of the 26) because these sites generally transmit higher seismic stresses to the piping systems. The study also analyzed two plants founded on soil of varying characteristics. NUREG-1903 provides more information on the approach used to evaluate direct piping failures.

Since the completion of NUREG-1903, all currently operating nuclear power reactor licensees have updated their seismic hazard and screening reports (SHSRs) in response to the NRC's letter, "Request for Information Pursuant to Title 10 of the *Code of Federal Regulations* 50.54(f) Regarding Recommendations 2.1, 2.3, and 9.3 of the Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident," dated March 12, 2012 (Ref. 41), and associated information requests. These recent updates may impact the NUREG-1903 results, and if inspections of limiting locations are not performed, a plant-specific analysis should be used to demonstrate the low likelihood of direct PLP system failure due to a rare seismic event. Sections B.2.2, B.2.3, and B.2.5 of this RG include information associated with acceptable approaches to evaluate direct seismic failures, while section B.2.6 contains information to evaluate indirect seismic failures. Both analyses are necessary to demonstrate the plant-specific applicability of the NUREG-1903 results if limiting locations are not inspected.

B.2.2 General Approach

For the cases studied in NUREG-1903, large circumferential flaws (i.e., flaw lengths approximately 80 percent of the pipe circumference) fail under rare seismic events when the flaw depth is a significant percentage of the wall thickness. Specifically, for a $10^{-5}/\text{yr}$ seismic event, the critical flaw depth is approximately 35 percent of the wall thickness, while for a $10^{-6}/\text{yr}$ seismic event, the critical flaw depth is approximately 25 percent of the wall thickness for the limiting thermally aged stainless-steel welds considered in the analysis. It is unlikely that such extensive flaws would exist within the PLP if a rare seismic event were to occur. However, because the NUREG-1903 analysis was not bounding (e.g., the analysis did not consider thermal embrittlement of cast austenitic stainless steel (CASS) and other materials nor the highest potential seismic stresses), the actual critical flaw depth for a specific plant may be smaller than these estimates. Therefore, this guidance provides various approaches that an entity with a new or existing plant applying to adopt 10 CFR 50.46a can use to demonstrate that the likelihood of direct failures in the PLP and RCPB components is consistent with the NUREG-1903 results. Figure 2, located at the end of this section, illustrates the process for this phase of the evaluation.

One approach is applicable if the limiting locations identified for the section B.2.3 analysis are included within the entity's ISI program and inspected during every ISI interval. As long as no significant indications are found under this program, no other evaluation is required. If significant indications are present, additional analysis is required to demonstrate their acceptability.

Plants with limiting locations that are not part of their ISI program need an evaluation to demonstrate the applicability of the NUREG-1903 results. The simplest approach for performing this evaluation is to demonstrate that the subject plant is bounded by the NUREG-1903 results. In this bounding analysis, the entity should demonstrate that the plant-specific PLP stresses, materials, material properties (including any aging-related property changes), and site-specific hazard information individually falls within, or is bounded by, the ranges considered in NUREG-1903. If these conditions are satisfied, the bounding critical flaw depths calculated in NUREG-1903 as described above will also bound the value that would be calculated for the specific plant.

If this evaluation option is not applicable, analysis is needed to directly assess the impact of surface flaw sizes using either a plant-specific deterministic or a probabilistic analysis. The objective of the deterministic plant-specific flawed piping analysis described in this guide is to calculate critical flaw depth for a long surface flaw (i.e., length equal to 80 percent of the component circumference) that corresponds to a seismically induced failure frequency of 10^{-6} /yr or less. This metric is chosen to ensure that the seismically induced risk of direct PLP failure is significantly less than the risk associated with failures larger than the TBS under normal operational loading (as defined in NUREG-1829). As previously discussed, the TBS was selected so that the failure risk, based on the NUREG-1829 results, was less than 10^{-5} /yr.

An approved PFM analysis that demonstrates that the risk associated with direct piping failure that appropriately considers aging effects, along with the possibility of flawed components in PLP systems, is also an acceptable alternative analytical approach. Such analyses should identify the most risk-significant failure locations based on the plant configuration and the response to plant-specific seismic hazard information in conjunction with the associated piping and weld materials fracture toughness properties. These properties should reflect the effects of applicable aging mechanisms over the entity's licensing period. Further, these analyses can use the results of preservice inspections or ISIs performed at those most likely seismic failure locations for informing the flaw distribution(s) used within the PFM analysis such that the distribution(s) is representative of the plant's service history.

B.2.3 Limiting Locations Selection

The analysis scope (figure 2) entails identifying limiting locations⁶ within the PLP (i.e., those with the highest failure potential) for subsequent evaluation. Only those piping systems having an inner diameter greater than the TBS are within the analysis scope. The limiting locations have the combination of high (or the highest) normal plus seismic stresses and low (or the lowest) material toughness properties such that the smallest critical flaw sizes are obtained at those locations.

These locations can likely be identified without detailed knowledge of the actual material properties and stresses within the PLP. However, subsequent steps may require that refined information. The ASME Code or other design stress and material information can be used to aid in the initial selection of the limiting locations. A location's susceptibility to degradation mechanisms that can lead to cracking (e.g., intergranular SCC, primary water SCC, or fatigue) is another important consideration. Finally, other important considerations when selecting limiting locations include effects on the material properties

6 The entity may need to analyze more than one limiting location if there are several locations with similar combinations of relatively high normal plus seismic operating loads and relatively low material toughness such that the location leading to the smallest critical surface flaw is not readily apparent.

associated with (1) the elevated loading rates associated with a seismic event (e.g., dynamic strain aging), (2) the age-related degradation of material toughness properties (e.g., thermal aging of CASS, stainless-steel welds, and other applicable PLP materials), and (3) uncertainties in the material behavior. Age-related considerations need to be applicable over the entity's licensing period.

All limiting PLP locations may be inspected as part of the entity's ISI program (figure 2). For entities implementing a risk-informed ISI program in accordance with ASME Code Case N-716-2, Examination Category R-A, Item R1.20 welds (i.e., welds not subject to a degradation mechanism) that are also limiting PLP locations may be inspected as well. Such welds, however, can be credited as part of the NRC-approved, risk-informed PLP inspection sample required in 10 CFR 50.46a(b)(3).

B.2.4 Applicability Demonstration Through the In-service Inspection Program

For those limiting locations that are part of an ISI program, the plant-specific acceptability of NUREG-1903 can be demonstrated through the successful application of that program. All potential PLP limiting locations may be candidates for inspection, assuming they are manufactured using common materials and fabrication techniques, including austenitic or ferritic welds between wrought base metals, mitigated Category A circumferential welds (for BWRs), dissimilar metal nickel alloy welds mitigated according to ASME CC N-770 (for PWRs), and austenitic welds between CASS base metals. This approach requires use of a qualified inspection technique, implemented through 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," or equivalent, quality assurance provisions. The technique should be for length and, preferably, depth sizing. Techniques with qualified depth sizing exist in ASME Code, Section XI, for all common materials used in possible limiting locations except for welds used to join CASS component(s). Further, the limiting locations should have sufficient accessibility so that inspection covers the portion of the limiting weld location associated with the highest seismic stresses.

As long as the ISI program does not identify indications in these limiting locations that exceed the ASME Code, Section XI, IWB-3500, acceptance criteria, no additional analysis is required to demonstrate applicability of the NUREG-1903 results. Preexisting indications that were not repaired before applying a mitigation technique also require no additional analysis as long as they meet the IWB-3500 criteria. If any indications are present that exceed the IWB-3500 acceptance criteria, they should be analyzed and meet the ASME Code, Section XI, IWB-3600, acceptance criteria with the additional provision that it be demonstrated that failure under a mean 10^{-6} /yr seismic stress applied stress using a structural factor of 1. The seismic stresses and material properties used for this analysis can be determined using any of the acceptable approaches (i.e., in sections B.2.5.1 and B.2.5.2) described in this guidance. If an inspected limiting location cannot meet these criteria, an alternative approach is to conduct a more realistic deterministic or probabilistic analysis. Section B.2.5 provides more background on these analyses. Another option is to either replace the component or repair the indications such that the component is restored to an effectively unflawed state.

B.2.5 Applicability Demonstration Through Analysis

B.2.5.1 Component Stresses

This guidance gives three acceptable options for determining the component level stresses resulting from the seismic loading (figure 2). Option I applies the NUREG-1903 results directly, while Option II performs a plant-specific calculation using the NUREG-1903 approach. Option III determines the component stresses by direct analysis. Options I and II are simpler and therefore are intended to be more conservative than Option III. Option III is significantly more complex. The level of complexity

associated with Option III also increases if fewer conservative assumptions are employed to develop more realistic or best estimate results.

B.2.5.1.1 Option I: Use NUREG-1903 Results

NUREG-1903 analyzed 26 PWR plants east of the Rocky Mountains. This option is only available to the specific plants analyzed in NUREG-1903. Appendix A lists these plants and provides the applicable design SSE PGAs. The NRC staff obtained limiting locations, normal operating stresses (i.e., pressure, bending, membrane, deadweight, thermal expansion), and SSE stresses for these plants from LBB submittals. The staff then extrapolated the SSE-level stresses to component stresses associated with a 10^{-6} /yr seismic event using the approach described in sections 4.4 and 4.5 of NUREG-1903. Appendix A to this RG also lists the locations, relevant LBB information, and associated 10^{-6} /yr seismic stresses for each plant analyzed in NUREG-1903. An existing plant using this approach, however, will need to verify that the 10^{-6} /yr seismic stresses used in the NUREG-1903 analysis remain either conservative or representative based on its latest SHSR (Ref. 41).

B.2.5.1.2 Option II: NUREG-1903 Scale-Factor Method

If the NUREG-1903 analysis did not evaluate the plant's limiting normal operating plus seismic component stresses or the analysis no longer represents the plant's seismic hazard, Option II uses the scale-factor method described in NUREG-1903, sections 4.4 and 4.5, to determine the component stresses. Appendix A to this regulatory guide provides scale factors for the seismic hazard associated with all PWR plant sites. The component stress using this approach should be determined from the latest information contained in the plant's SHSR for both Service Level D (i.e., SSE stresses) and seismic stresses representative of a 10^{-6} /yr probability of exceedance.

B.2.5.1.3 Option III: Direct Analysis

The objective of this analysis is to determine the normal operating plus peak axial seismic stresses at the limiting locations through a direct analysis of the plant. The site-specific hazard information used in this analysis should reflect all current requirements and updates to the seismic hazard models (e.g., as required by American National Standards Institute (ANSI)/American Nuclear Society (ANS) 58.21, "External Events in PRA Methodology" (Ref. 39). The foundation properties should use an appropriate model of the soil and rock properties that are applicable to the site. If the site condition is very stiff rock and the UHS is dominated by low-frequency motion, it is conservative to treat the structure as fixed base. ANSI/ANS-58.21 provides more information and details related to dynamic modeling considerations. The model of the PLP within the reactor building dynamic model may be either a detailed or a simplified PLP model. The simplified PLP model should incorporate appropriate mass and stiffness characteristics to represent the overall plant behavior. If a detailed PLP model is chosen, the stresses at the limiting locations are used directly in subsequent fracture mechanics calculations. If the entity chooses a simplified PLP model, the output from the overall reactor building dynamic model (i.e., time histories or response spectra at PLP support points) at the limiting locations should be used as input to a separate, detailed model of just the PLP. The entity should then use the stresses calculated from this separate, detailed PLP model within subsequent fracture mechanics calculations.

B.2.5.2 Material Properties

The NUREG-1903 analysis assumed toughness and strength properties representative of carbon-steel base metals and welds, as well as stainless-steel SAW material, both with and without adjustment for thermal aging. The NUREG-1903 analysis derived the baseline (i.e., without thermal aging effects) stainless-steel SAW J-R curve (a tool for evaluating material fracture toughness in the ductile

region) from a statistical analysis of data in the Fracture Mechanics Database for Nuclear Piping Materials (Ref. 42). No statistically significant differences exist between the toughness of shielded metal arc welds (SMAWs) and SAWs. This finding is the technical basis for the current version of ASME Code, Section XI, Appendix C, which contains only one Z-factor equation for these two weld types. The mean minus one standard deviation quasi-static J-R curve from the SMAW and SAW materials was also adjusted to account for dynamic rate and cyclic loading effects that occur during an earthquake (Ref. 5). NUREG-1903 provides additional guidance for addressing the effects of elevated loading rates on material toughness (i.e., J-R curve) properties. The thermally aged stainless-steel SAW J-R curve properties were obtained from a previous evaluation of this effect (Ref. 43). Finally, the NUREG-1903 evaluation used a modified J-R curve that more realistically predicted the results of large-scale piping tests (Ref. 44). This procedure was used to develop modified Z-factors (see appendix A to this guide) for the limiting materials evaluated in NUREG-1903.

The plant-specific material properties at each limiting location (figure 2) should also reflect the inherent uncertainty and variability in those properties, including a consideration of aging effects. The analysis can address variability in J-R and stress-strain properties by evaluating the impact that alloying, compositional, and microstructural differences have on the measured properties. These differences should reflect the range of allowable materials conditions and represent the variability induced by fabrication or processing methods applied within the plant.

Considering properties reflective of limiting allowable manufacturing ranges that produce lower strength and toughness properties is a straightforward approach to address variability. Uncertainties in both material toughness and strength properties for these conditions can then be addressed by obtaining a statistically significant number of J-R and stress-strain curves that represent the material at each limiting location and determining the mean minus one standard deviation J-R and stress-strain curves after accounting for dynamic rate, cyclic loading, and thermal aging effects, as in NUREG-1903. Alternatively, the entity can choose an appropriate J-R or stress-strain curve from the ASME Code if it can be demonstrated that the curve selected is more conservative than that expected for the material at each limiting location after accounting for both variability and uncertainties in the properties.

B.2.5.3 Surface Flaw Analysis

This RG provides two deterministic analysis options for determining the critical surface flaw size using the approach outlined in NUREG-1903 (figure 2). The first, and simplest, option allows the entity to directly leverage the NUREG-1903 results without any additional calculations, so long as several conditions are satisfied. The second option is applicable if not all the conditions required for the first option are satisfied. This option requires that the entity conduct a plant-specific analysis that follows the calculation steps detailed in NUREG-1903 (see appendix B to this RG) to determine the critical surface flaw size or through a representative PFM analysis to demonstrate that the failure risk of the PLP due to rare, seismic loading is acceptable. Section C of this RG presents the details associated with each option.

Section 4.5.2 of NUREG-1903 provides more background on the plant-specific deterministic analysis (section C.2.5.3.2 of this RG). In addition, appendix B to this RG describes step-by-step procedures for conducting this analysis and provides a sample calculation. This approach is consistent with the allowable flaw size determination described in appendix C to ASME Code, Section XI, although no additional margin (i.e., structural factor of 1.0) is applied to the seismic stresses. Part of this plant-specific analysis requires a potential adjustment to correct for material plasticity if the entity used elastic calculations to determine the normal operating plus 10^{-6} /yr seismic stress (i.e., total stress). Total stress values less than the material yield strength do not require additional correction. However, if the total stress from an elastic analysis is greater than the material yield strength, the entity should multiply the total stress by a correction factor of $0.5(S_y + S_u)/6.3S_m$, where S_y is the material yield strength; S_u is the

material ultimate strength; and $6.3S_m$ represents the combined pressure, deadweight, and seismic stresses at failure from elastic analyses. This failure criterion was developed from seismic testing of unflawed nuclear piping components (Ref. 45).

Another component of the analysis determines a correction for the Z-factor. The NUREG-1903 analysis calculated revised Z-factors to account for seismic loading, dynamic strain aging, and thermal aging effects, as appropriate for the materials evaluated in NUREG-1903. Appendix A to this guide provides these revised Z-factors. The entity can also determine the Z-factor for the nominal pipe diameter at each limiting location using the equations supplied in NUREG-1903 for materials not evaluated in NUREG-1903. Section B.2.5.2 provides more information on the Z-factor calculation in NUREG-1903. Alternatively, the entity can determine the critical flaw size using EPFM predictions of component failure without applying the Z-factor approach. In this analysis, the entity should use the applied stresses determined in section B.2.5.1 and the material properties determined in section B.2.5.2. NUREG/CR-6298, "Fracture Behavior of Short Circumferentially Surface-Cracked Pipe," issued November 1995 (Ref. 46), provides additional detail on directly calculating component failure using EPFM. The probabilistic analysis option (section C.2.5.3.3) requires a sensitivity analysis to assess the impact on the mean failure probability stemming from significant analysis parameters. The principal variables to consider for such analysis include the surface flaw length, the applied $10^{-6}/\text{yr}$ seismic stress, the fracture toughness, and the flaw growth rate distributions. The fracture toughness and crack growth rate distributions are expected to have less uncertainty and are likely to be supported by sufficient data that the distributions are expected to be reasonably accurate. It is acceptable to add a conservative bias to these distributions if data are lacking based on expected generic or ASME Code properties. If either of these expectations is met, further sensitivity studies on these variables are not expected to result in significant detrimental effects on the mean failure likelihood. Alternatively, sensitivity studies on these variables should be performed to assess their impact.

The surface flaw length and applied seismic stress distributions, however, are expected to be more uncertain, and these variables are known to more significantly affect the calculated mean failure frequencies (Ref. 47 and 48). Therefore, sensitivity analyses to evaluate the effects of these variables are required (section C.2.5.3.3). While there are many approaches that can be used to perform sensitivity analyses, a reasonable approach is to increase both the magnitude and frequency of the mean seismic frequency to values that are one standard deviation greater than the mean while simultaneously increasing the standard deviation by a factor of 2. Similarly, the mean and standard deviation of the flaw length distribution can be increased such that there is a 10 percent probability that the initial surface flaw length is 40 percent of the inner pipe circumference at the limiting locations. The likelihood of such flaws, based on operating experience, is expected to be at least an order of magnitude less than this probability, but it is anticipated that most limiting locations will be able to demonstrate acceptable seismic failure frequencies even with such a conservative assumption.

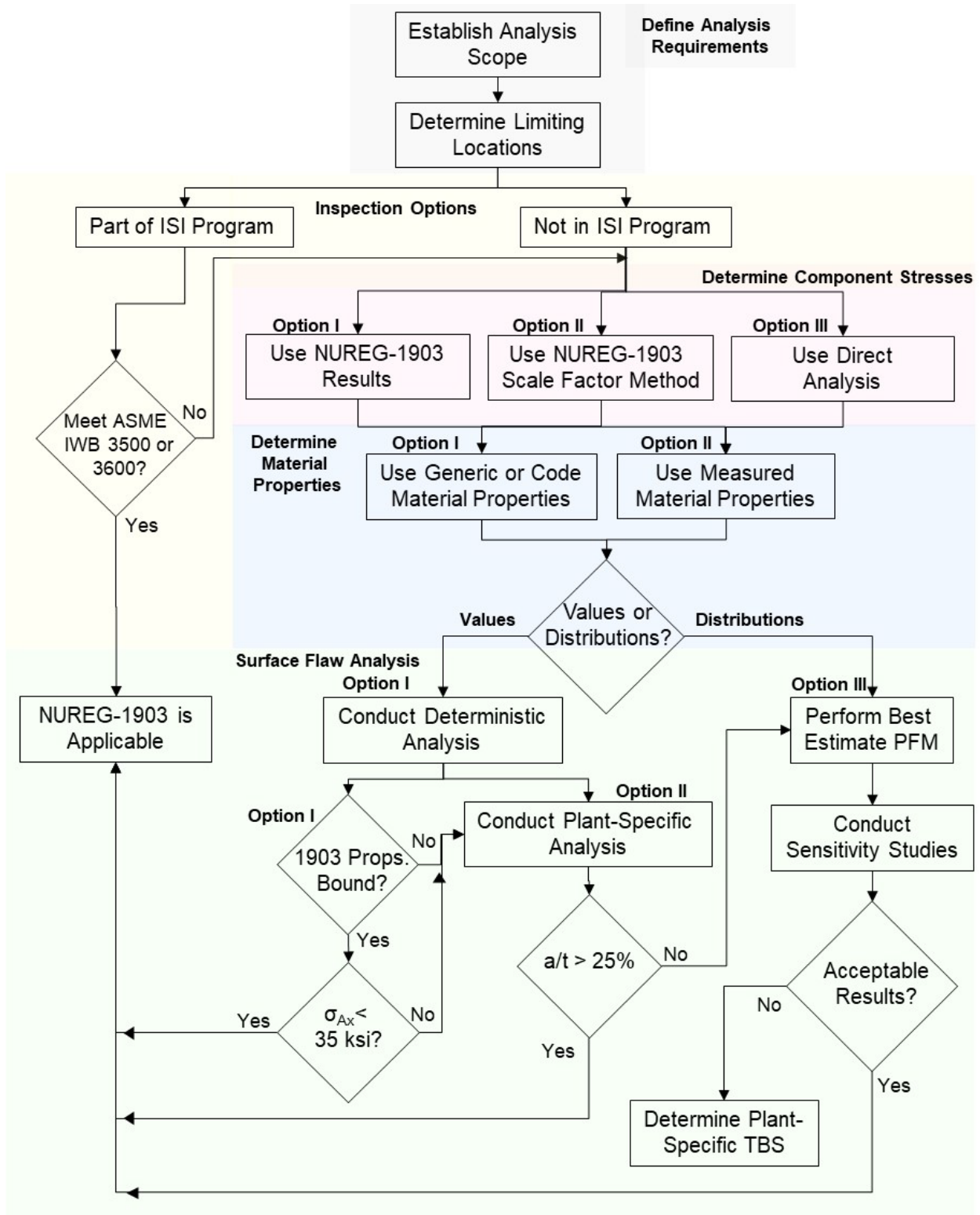


Figure 2. Evaluating seismically induced risk of direct PLP failures

B.2.6 Seismically Induced Risk of Indirect Primary Loop Piping or Reactor Coolant Pressure Boundary Component Failures

Indirect failures are primary system ruptures that are a consequence of failures in primary and nonprimary system components or structural support failures (such as reactor coolant pump supports and steam generator supports). Structural support failures could then cause displacements in components that stress and, in turn, fail the piping. The NRC performed studies on two plants to estimate the conditional pipe failure probability due to structural support failure given a large, rare earthquake (i.e., 10^{-5} to 10^{-6} /yr). These studies used generic seismic hazard curves from NUREG-1488, "Revised Livermore Seismic Hazard Estimates for Sixty-Nine Nuclear Power Plant Sites East of the Rocky Mountains," issued April 1994 (Ref. 38). The results of these studies, as described in NUREG-1903, showed that indirectly induced piping failure attributable to major component support failure for those two plants using representative major support fragilities has a mean failure probability on the order of 10^{-6} /yr, which is less than the NUREG-1829 LOCA frequency of 10^{-5} /yr used as the starting point for selecting the TBS criterion. This has been confirmed by the results of the staff's reassessment of the original NUREG-1903 studies using the updated seismic hazard information (Ref. 24).

The NRC also more generically assessed the relative importance of indirect seismic failures on the initial TBS. Generally, the median seismic capacities for both the primary piping system and primary system components are typically higher than other safety-related components within the nuclear power plant. Because of these relative capacities, the NRC expected that a seismic event of sufficient magnitude to cause consequential failure within the primary system would also induce failure of components in multiple trains of mitigation systems or even induce multiple reactor coolant system pipe breaks. Consequently, the risk contribution from seismically induced indirect failures was expected to depend more heavily on the relative fragilities of plant components and systems than the size of the TBS. Therefore, at the time, the NRC determined that adjustment to the TBS for seismically induced indirect LOCAs was not warranted.

However, the NRC noted in NUREG-1903 that indirect failure analyses are highly plant specific. It is likely that the small sample of example plants assessed in the NRC analyses is not limiting for all plants. Further, it is also possible that the plant-specific relative seismic fragility characteristics among components and supports could result in unacceptable risk for seismically induced indirect LOCAs with break areas that are greater than the TBS. Therefore, an analysis using plant-specific hazard curves and component and support fragilities is needed to demonstrate that the indirect seismic failure frequency of a passive system that could lead to a rupture larger than the TBS is significantly less than 10^{-5} /yr. This will provide reasonable assurance that the seismic risk is less than the risk associated with normal operations used as the basis for the TBS. If the entity cannot demonstrate that the indirect failure risks associated with the PLP and RCPB components are not significantly less than 10^{-5} /yr, then the generic TBS is not applicable and an additional basis for implementing the rule is necessary.

The plant-specific assessment of indirect piping failures should use the most up-to-date seismic hazard information. Similarly, plant-specific component and support fragilities that appropriately account for any age-related degradation should be considered. Use of this information within a plant-specific seismic PRA that complies with RG 1.200, ASME/ANS RA-Sa-2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," issued February 2009 (Ref. 49), and ANSI/ANS-58.21 is one acceptable way to demonstrate that the indirect seismic risk associated with LOCAs greater than the TBS is acceptable. The EPRI "Seismic Probabilistic Risk Assessment Implementation Guide," issued December 2013 (Ref. 50), provides guidelines for performing state-of-the-art PRAs and is intended to satisfy the ASME/ANS RA-Sa-2009 and ANSI/ANS-58.21 requirements and the RG 1.200 guidance. The EPRI guide addresses the development and implementation of plant-specific seismic hazard analysis, seismic fragility evaluation, and systems

analysis and quantification. A seismic PRA that demonstrates that the plant's baseline risk associated with indirect seismic failures contributing to a LOCA that is larger than the TBS is less than 10^{-6} /reactor yr adequately demonstrates that the risk of these failures is not significant.

Methods other than seismic PRAs (e.g., seismic margin assessment in NUREG/CR-4334, "An Approach to the Quantification of Seismic Margins in Nuclear Power Plants," issued August 1985 (Ref. 51)) may also be acceptable for performing this analysis if their use and applicability are appropriately justified. Compared with a full-scope seismic PRA, these methods employ a simple but efficient seismic risk estimate methodology (i.e., simple convolution of seismic hazard and plant-level fragility) and produce a bounding seismic risk estimate for comparison with the TBS criterion. As such, they are more appropriate for those plant sites located in low-to-medium seismic risk zones that do not require the use of the most sophisticated seismic risk analysis model. Such analyses should also account for aging effects and demonstrate that appropriate margin for indirect failures of the PLP and RCPB components exists. Also, the analysis should demonstrate that this risk should be a minor contributor to the plant's total seismic margin, or risk. DG-1426 contains more details about the plant's PRA and the calculation of the plant's baseline risk as part of the risk assessment conducted to implement 10 CFR 50.46a.

B.3 Plant Changes That May Affect Loss-of-Coolant Accident Frequencies

In 10 CFR 50.46a(h), the NRC provides requirements that a risk-informed evaluation of the proposed plant changes must meet, while DG-1426 includes guidance on meeting those requirements. As stated in 10 CFR 50.46a(h)(3), proposed changes made under this rule must maintain adequate defense in depth, retain adequate safety margins to account for uncertainties, and implement adequate performance-measurement programs to ensure the risk-informed evaluation used to demonstrate that the acceptability of the proposed changes continues to reflect the actual plant design and operation. In particular, the performance-measurement programs must be designed to detect degradation of the PLP or RCPB component, or other components whose failure could induce PLP or RCPB component failure, before plant safety is compromised. Further, these programs must provide feedback of information and timely corrective action and monitor the SSCs at a level commensurate with their safety significance.

Although DG-1426 addresses the general approach for conducting the required risk-informed evaluation process, 10 CFR 50.46a(h)(1)(iii) and 10 CFR 50.46a(h)(2)(v), as applicable, require that the proposed plant changes do not significantly increase LOCA frequencies or invalidate the evaluation demonstrating the applicability of the TBS to the entity's facility. This section of this guide describes an acceptable evaluation for demonstrating that the proposed plant changes have no significant impact on the LOCA frequencies such that the TBS remains applicable subsequent to the plant changes.

Such an evaluation is necessary because inherent in the elicitation that formed the basis for the NUREG-1829 results is the assumption that all future plant operating characteristics will be essentially consistent with past operating practice. The NUREG-1829 elicitation did not consider the effects of operating profile changes because 10 CFR 50.46a does not prescribe specific changes; rather, it enables broad changes as long as the established risk-informed criteria are satisfied. Some potential operational changes may increase the LOCA frequencies compared to those existing before the plant changes. Additionally, operating profile changes are inherently plant specific, which is inconsistent with the elicitation objective to develop generic frequency estimates. The elicitation did not address the plant-specific changes and uncertainty.

The assumption that a plant's operating characteristics are constant helps ensure that the operating experience related to degradation in the PLP and RCPB components remains applicable over the remaining licensing period. One example of a plant change that may lead to degradation not observed

in prior operating experience is a significant power uprate. A power uprate may alter relevant plant operating characteristics (e.g., temperature, environment, flow rate) such that future degradation and, consequently, LOCA frequencies are increased. To avoid this situation, 10 CFR 50.46a(h) requires the entity to evaluate the potential impact on the LOCA frequencies from any proposed change to the plant design, configuration, operations, or maintenance.

The evaluation scope should consider potential impacts on the LOCA frequencies associated with both direct and indirect failures of the PLP and the RCPB components that could lead to a LOCA that is greater than the TBS. For the purposes of this analysis, direct PLP and RCPB failures are those that are not caused by failure of another SSC. That is, they fail on their own. Conversely, indirect failures are those that could result from the initial failure of other plant SSCs, including PLP and RCPB component supports and nonprimary pressure-boundary-retaining components. Failures under normal operational loading, design-basis and other accident loading, and rare seismic loading, as in the NUREG-1903 analysis, should be addressed. Additionally, effects of age-related degradation should be considered.

A risk-informed evaluation must, under 10 CFR 50.46a(h), demonstrate that the plant changes do not cause a significant increase in the frequency of LOCAs with sizes greater than the TBS. The evaluation should document the assumptions and approach used to perform the analysis. Any potential impacts of the proposed plant changes that could affect causal phenomena or attributes associated with such LOCAs should also be described. The evaluation of the significance of any such relevant implications should then be documented along with the acceptance criteria used to assess the significance. The basis for the acceptance criteria should be justified, as appropriate.

The performance monitoring program that will be used to evaluate changes in plant attributes, characteristics, or responses that may impact LOCA frequencies (e.g., accelerated material degradation) is an important consideration in such assessments. Therefore, this program should be described, including the monitoring parameters and their acceptance criteria. Further, the appropriateness of monitoring parameters and their acceptance criteria for demonstrating that the plant change has not significantly affected LOCA frequencies should be justified.

B.3.1 Plant Changes That May Affect Direct Failure Frequencies

As indicated in section B.1, LOCA frequencies within the PLP and RCPB are a function of several variables, including the materials, fabrication methods, service environment, applied loading, age-related degradation mechanisms, geometry and configuration, and maintenance and mitigation associated with each potential failure location. Therefore, the entity's evaluation should demonstrate that the proposed plant changes under 10 CFR 50.46a do not significantly alter any of these critical variables such that the plant's LOCA frequencies increase. Two acceptable evaluation options are described for demonstrating that the LOCA frequencies are not significantly affected, and one acceptable approach is described for confirming that the NUREG-1903 analyses are not significantly affected. Other proposed approaches may be acceptable.

Whichever analysis option is chosen, the entity is required under 10 CFR 50.46a(d)(4) to analyze any proposed plant change that may cause the plant's LOCA frequencies to increase. The analysis should describe the approach used, identify potential impacts of the proposed changes on PLP and RCPB structural integrity, evaluate the significance of these impacts on the LOCA frequencies, and ensure that the changes satisfy risk-informed requirements as required in 10 CFR 50.46a(h). DG-1426 contains more guidance on satisfying the risk-informed requirements. Effective performance monitoring is an important risk-management principle for providing assurance that the TBS will remain applicable after enacting the proposed plant changes. Figure 3 (found at the end of this section) illustrates the process for this evaluation.

B.3.1.1 Option I: Effects on NUREG-1829 Variables

Option I explicitly evaluates the impact stemming from changes related to the following plant variables: materials, fabrication methods, service environment, applied loading, age-related degradation mechanisms, geometry and configuration, and maintenance and mitigation. The analysis should initially determine whether the plant change affects any of these variables. For instance, if the PLP and RCPB materials will not be modified, then the plant change is not relevant to this variable. If the change is relevant, the entity should next assess the significance of the plant change. Significant changes are those that could increase the LOCA frequencies such that NUREG-1829 (or the entity's plant-specific original analysis) would not be applicable to the plant after the change is enacted. For instance, if the plant change increases the flow-induced vibration loading magnitude and frequency within the PLP, this may increase its failure likelihood unless appropriate mitigation is employed such that LOCA frequencies are unchanged. The review standard (RS) for extended power uprates (EPUs) (Ref. 52) provides additional guidance related to topics that may need to be considered as part of these analyses.

While the impact of the proposed change on all the above variables should be considered, the NRC assumes that entities will not make changes to the PLP or RCPB geometry or configuration nor that new materials or fabrication techniques will be implemented under 10 CFR 50.46a. The NRC expects that plant changes enacted under this rule will most likely impact the service environment, applied loading, the rate or occurrence of age-related degradation, and maintenance and mitigation effectiveness. For instance, a plant change that increases the primary system temperature may increase the rate of SCC, thermal embrittlement, or the thermal loads within affected systems. In this hypothetical example, new or accelerated degradation mechanisms could be demonstrated to be unlikely if the temperature increases are not significant. Increased performance monitoring to measure system temperature changes, loading fluctuations, and degradation rates would then provide assurance that the TBS remains applicable.

B.3.1.2 Option II: Review Standard for Extended Power Uprates

This option uses guidance and criteria based specifically on the RS for EPUs (Ref. 52) to evaluate the likelihood of changes in the direct failure frequency resulting from the proposed plant change. The RS identifies several evaluations that, depending on the proposed plant changes, may be pertinent for determining the potential effects of plant changes on the failure of the PLP and RCPB components. The RS also identifies related SRP sections and the applicable regulations addressed by the evaluations and provides other regulatory guidance, as appropriate. Evaluations identified in this section of this guide that are unaffected by the proposed changes can be omitted by providing appropriate justification.

The topic areas in the EPU guidance (Ref. 52) pertaining to the reactor pressure vessel that may be affected by the proposed plant changes include the reactor vessel materials surveillance program, with review criteria contained in SRP Section 5.3.1, "Reactor Vessel Materials"; the pressure-temperature limits and upper-shelf energy, with review criteria in SRP Section 5.3.2, "Pressure-Temperature Limits, Upper-Shelf Energy, and Pressurized Thermal Shock"; and, for PWR plants, pressurized thermal shock, with review criteria in SRP Section 5.3.2. Topic areas pertaining to the PLP include LBB, with review criteria in SRP Section 3.6.3; for PWRs, the chemical and volume control system, with review criteria in SRP Section 9.3.4, "Chemical and Volume Control System (PWR) (Including Boron Recovery System)"; and for BWRs, the reactor water cleanup system, with review criteria in SRP Section 5.4.8, "Reactor Water Cleanup System (BWR)." Topic areas on RCPB materials, with review criteria in SRP Section 5.2.3, "Reactor Coolant Pressure Boundary Materials," and pressure-retaining components and associated supports, with review criteria in SRP Section 3.9.1, "Special Topics for Mechanical Components"; Section 3.9.2, "Dynamic Testing and Analysis of Systems, Structures, and Components"; Section 3.9.3, "ASME Code Class 1, 2, and 3 Components, and Component Supports, and Core Support

Structures”; and Section 5.2.1.1, “Compliance with the Codes and Standards Rule, 10 CFR 50.55a,” pertain to proposed changes that may affect all PLP and RCPB components.

B.3.1.3 Evaluate Effects on NUREG-1903 Analyses

The NUREG-1903 applicability determination (section B.2) relies on the entity’s ISI program or analysis, or both, to demonstrate plant-specific applicability. If the ISI program is the basis for this determination, the evaluation of the proposed plant changes should assess whether these changes significantly degrade the ISI program. Inspectability of the limiting locations is one consideration. Inspectability could be degraded by reduced access to the limiting weld location(s) such that sufficient inspection coverage is not possible or if the weld location(s) otherwise becomes harder to inspect. While this scenario is not anticipated, a change in inspection technique could also decrease the reliability and accuracy for detecting flaws before they challenge structural integrity. Any indications present at limiting locations are also evaluated to ensure that component failure is unlikely under rare seismic loading. Proposed changes that increase the normal operating or rare seismic component stresses or decrease the strength or fracture toughness of materials at the limiting locations should be assessed. Further, the evaluation of plant changes should assess whether the changes make it significantly less likely that any inspections performed at the limiting locations would detect flaws before they reach the critical surface flaw depth from the NUREG-1903 analysis (e.g., due to faster cracking rates).

For limiting locations addressed by analysis, the evaluation of the effect of the proposed plant changes should consider their effects on both plant-specific normal operating and seismic stresses, as well as material properties, to demonstrate that the surface flaw analysis (section C.2.5.3) remains acceptable. This part of the evaluation should assess effects of the plant changes that would increase the loads (section C.2.5.1), decrease the materials’ fracture toughness (section C.2.5.2), or increase the crack propagation rate at the limiting PLP locations (section C.2.3).

A technical basis should be developed that demonstrates that the plant changes do not significantly affect the plant-specific NUREG-1903 acceptability determination (section C.2) commensurate with 10 CFR 50.46a(h)(1)(iii) or 10 CFR 50.46(h)(2)(v), as applicable. This analysis must be submitted in a request for NRC review and approval if required under 10 CFR 50.46a(c)(1)(i), 10 CFR 50.46a(c)(2), or 10 CFR 50.46a(h). Alternatively, if the entity cannot show that NUREG-1903 applicability is maintained after the proposed plant changes, the entity can modify the proposed changes such that the prior applicability is reestablished, reanalyze the limiting locations to directly account for the effects of the proposed changes as described in section C.2.5 of this RG, or both. Any such reanalysis must also be submitted for NRC review and approval if required under 10 CFR 50.46a(c)(1)(i), 10 CFR 50.46a(c)(2), or 10 CFR 50.46a(h).

B.3.2 Plant Changes That May Affect Indirect Failure Frequencies

The LOCA frequency estimates in NUREG-1829 only considered the contribution of direct piping system and RCPB component failures. While the recent effort to assess the continued adequacy of NUREG-1829 (Ref. 23) considered the impacts of secondary pipe failures on breaks greater than the TBS, NUREG-1829 does not explicitly address indirect failures resulting from either normal operations or during a seismic event, although such failures contribute to the total risk of a LOCA that is greater than the TBS. NUREG-1903 performed a limited analysis of such failures during a seismic event. As previously discussed, indirect PLP or RCPB failures are those that result from the initial failure of plant systems or components that are not part of the primary pressure boundary. Examples include (1) primary system over-pressurization transients caused by accidents resulting from human error, fires, or flooding that cause electrical and mechanical control systems to malfunction, (2) missiles from equipment failure, (3) damage from moving equipment, and (4) failures of SSCs in close proximity to the PLP and RCPBs.

The objective of the analysis of indirect failures is to demonstrate that the proposed plant changes negligibly increase the likelihood of indirect failures so that the NUREG-1829 and NUREG-1903 results, and hence the TBS, remain applicable to the plant.

This RG provides two acceptable options for demonstrating that NUREG-1829 remains applicable to the plant after enacting the proposed plant changes (see figure 3). Option I uses the results of prior indirect failure analyses that show compliance with existing regulations (e.g., for LBB or EPU approval). These analyses may also be applicable for demonstrating that the risk associated with indirect PLP and RCPB failures during normal operations is insignificant. If the proposed plant changes do not significantly affect these prior analyses, the results of NUREG-1829 remain applicable to the plant. If the proposed plant changes do impact the prior analyses, additional analysis (e.g., conducted in accordance with Option II) can be used to assess the significance of the plant changes on indirect failure frequencies. Alternatively, Option II can be chosen initially to explicitly evaluate the impact of the proposed plant changes without relying on prior indirect failure analyses. The method described in Option II is based on existing LBB (Ref. 11) and EPU (Ref. 52) guidance that is pertinent for addressing indirect failures.

B.3.2.1 Impact of Plant Changes on Dynamic Effects

The dynamic effects associated with a pipe rupture in the primary pressure boundary piping that is smaller than the TBS or within a nonprimary pressure boundary system could induce failure within the PLP and RCPB components. The objective of this part of the evaluation of the effect of proposed plant changes is to demonstrate compliance with GDC 4, such that the PLP and RCPB components remain adequately protected from the effects of these ruptures. Effects could include jet impingement loading, jet thrust loading, and pipe whip dynamic effects. The evaluation should consider the effect of proposed plant changes within these primary and nonprimary pressure boundary systems on the design adequacy of the PLP and RCPB components. SRP Section 3.6.2, “Determination of Rupture Locations and Dynamic Effects Associated with the Postulated Rupture of Piping,” contains specific review criteria. This analysis should specifically address the effects on PLP and RCPB component supports because support failures could initiate subsequent primary pressure boundary failures.

Flow-accelerated corrosion (FAC) is one potential degradation mechanism that could induce dynamic effects. The PLP and RCPB components that could rupture with break sizes greater than the TBS are generally not susceptible to FAC. A consideration of FAC would only be needed if the plant changes affect FAC in a susceptible component or piping system such that its failure could induce a rupture in the PLP or RCPB components bigger than the TBS. If analysis is needed, it should consider the effect of the proposed plant changes on FAC and the adequacy of the entity’s FAC program to predict the rate of loss. This demonstration is important to provide assurance that repair or replacement of damaged components can be made before they reach the minimum acceptable wall thickness, which substantially increases their failure probability. An approved structural evaluation may also be needed to determine the minimum acceptable wall thickness for the components undergoing degradation by FAC if ASME Code-allowable values are violated.

B.3.2.2 Impact of Plant Changes on Missile Protection

This evaluation should consider the effect of plant changes on possible PLP and RCPB component failures caused by missiles generated inside containment, as required by GDC 4. Missiles could result from in-plant component overspeed failures of high-speed rotating machinery, high and moderate pressure system ruptures, or failures of SSCs in close proximity to the PLP or RCPB components. Failures could occur in either safety-related or non-safety-related SSCs. An evaluation of the effect of plant changes should focus on any changes that may affect an existing, approved missile

protection analysis. SRP Section 3.5.1.2, “Internally-Generated Missiles (Inside Containment),” contains specific review criteria.

Objectives of this evaluation are to demonstrate the adequacy of the PLP and RCPB component missile protection while also ensuring the low likelihood of missile sources. Therefore, one acceptable method for demonstrating that the proposed plant changes are acceptable is to show that they will not substantively affect missile sources, the likelihood of missiles, and missile protection of the PLP and RCPB components. The analysis approach should identify any changes in the missile protection measures arising from (or as part of) these proposed changes and demonstrate that the existing or proposed missile protection systems or barriers adequately protect the PLP and RCPB component from failures.

For example, this analysis may demonstrate that increases in system pressures or component overspeed conditions that could result during plant operation or anticipated operational occurrences, or from changes in existing system configurations, do not affect the likelihood of missile generation. Alternatively, the analysis may demonstrate that the proposed plant changes do not affect system pressures and component overspeed conditions and that existing overspeed protection features are adequate such that overspeed conditions above the design values are very unlikely.

B.3.2.3 Impact of Plant Changes on Loss-of-Coolant Accident Frequencies Greater Than the Transition Break Size Due to Seismically Induced Indirect Primary Loop Piping or Reactor Coolant Pressure Boundary Component Failures

Section B.2.6 of this RG and DG-1426 provide guidance for performing the initial analysis of the plant risk associated with indirect seismic failures (i.e., external hazards or events in DG-1426) that could induce LOCAs greater than the TBS in PLP and RCPB components. This initial risk estimate discussed in section B.2.6 establishes the baseline plant risk associated with these failures. The change in risk due to proposed plant changes under 10 CFR 50.46a should be determined using analyses consistent with the analysis used to determine the baseline risk. For an entity with a self-approved risk-informed evaluation process, 10 CFR 50.46a(h)(1)(ii) requires that each individual plant change result in, at most, a minimal increase in risk. For an entity without a self-approved, risk-informed evaluation process, 10 CFR 50.46a(h)(2) requires NRC approval before implementing the changes. Further, 10 CFR 50.46a(h)(2)(ii) stipulates that each individual plant change should result in, at most, a very small increase in the core damage frequency and large-early release frequency (Ref. 15 and 17) and overall plant risk should remain small (Ref. 1). The allowable risk increases in 10 CFR 50.46a(h)(1)(ii) and 10 CFR 50.46a(h)(2)(ii) include risk sources both internal and external to the plant and for all modes of operation. The risk associated with plant changes that increase the frequency of LOCAs in the PLP or RCPB components due to seismically induced indirect failures is a subset of the total plant risk increase.

Each plant change also must satisfy 10 CFR 50.46a(h)(3) such that adequate defense in depth is maintained, sufficient safety margins are retained to account for uncertainties, and adequate performance-measurement programs are implemented to ensure the risk-informed evaluation continues to reflect actual plant design and operation. Regulations in 10 CFR 50.46a(h)(2)(iii) require entities without a self-approved, risk-informed evaluation process to evaluate the cumulative effect of the proposed and all previous changes made under 10 CFR 50.46a. In 10 CFR 50.46a(j)(3), the NRC requires that every 24 months, entities with a self-approved, risk-informed evaluation process provide a short description of each change involving minimal changes in risk made under 10 CFR 50.46a(h)(1) in the preceding 24 months and a brief summary of the basis for the entity’s determination, pursuant to 10 CFR 50.46a(h)(1)(iii), that the change does not invalidate the applicability evaluation made under 10 CFR 50.46a(c)(1)(i), or the plant-specific TBS evaluation made under 10 CFR 50.46a(c)(2), as applicable. DG-1426 provides guidance to demonstrate that proposed facility changes will satisfy the requirements in 10 CFR 50.46a(h). As indicated, the risk associated with LOCA frequency increases due

to indirect seismic failures is just a subset of the total increase in plant risk; the total increase in risk is limited by the rule acceptance criteria; and DG-1426 provides additional risk assessment guidance. Therefore, adhering to the DG-1426 guidance is one acceptable way to demonstrate that the seismically induced indirect failure risk to the PLP or the RCPB components associated with the proposed plant changes is acceptable such that the TBS remains applicable.

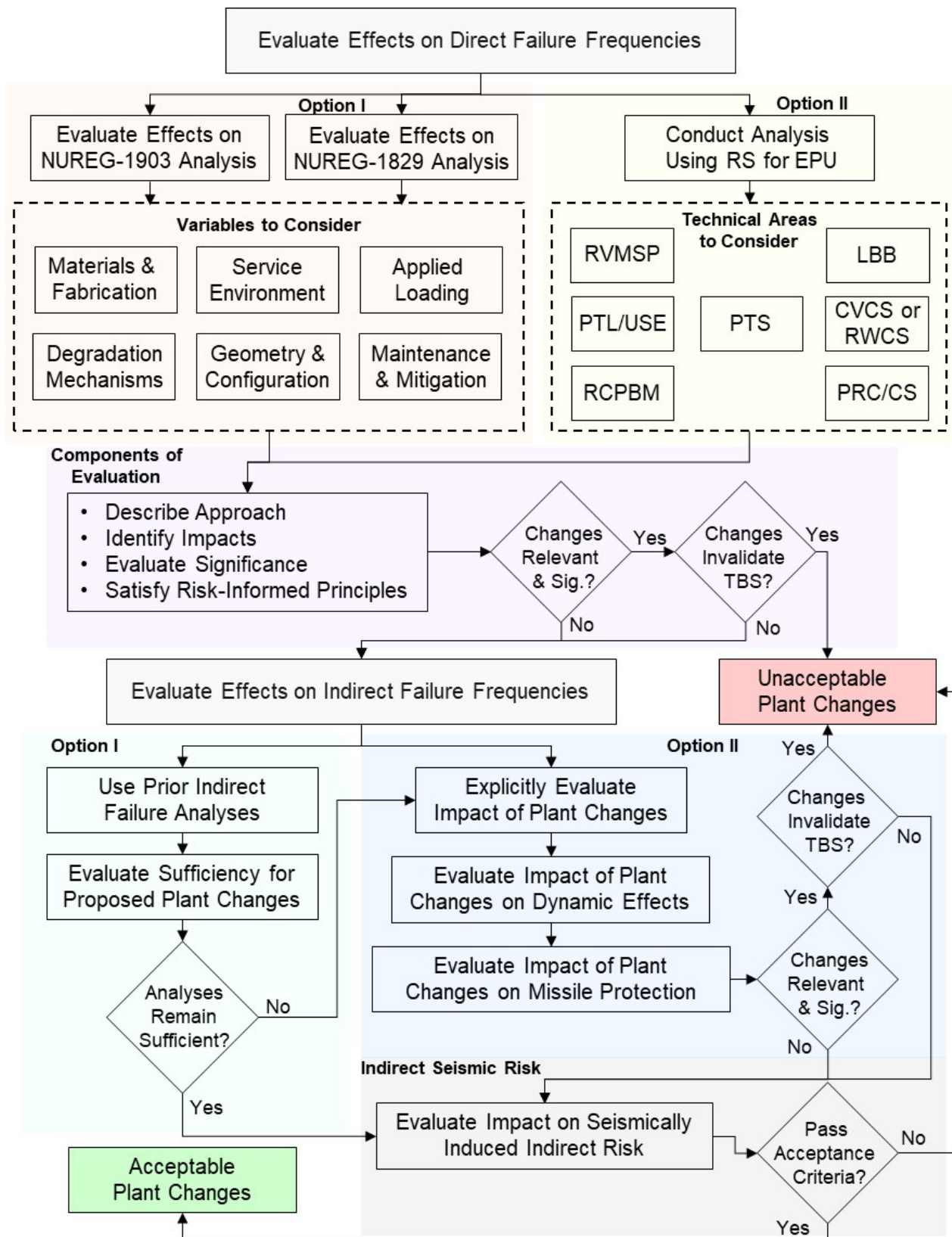


Figure 3. Evaluating the impact of plant changes

Consideration of International Standards

The International Atomic Energy Agency (IAEA) works with member states and other partners to promote the safe, secure, and peaceful use of nuclear technologies. The IAEA develops Safety Requirements and Safety Guides for protecting people and the environment from harmful effects of ionizing radiation. This system of safety fundamentals, safety requirements, safety guides, and other relevant reports, reflects an international perspective on what constitutes a high level of safety. To inform its development of this RG, the NRC considered IAEA Safety Requirements and Safety Guides pursuant to the Commission's International Policy Statement (Ref. 53) and Management Directive and Handbook 6.6, "Regulatory Guides" (Ref. 54).

The following IAEA Safety Requirements and Guides were considered in the development of the Regulatory Guide:

- IAEA Safety Standard Series No. SSG-48, "Ageing Management and Development of a Programme for Long Term Operation of Nuclear Power Plants," issued 2018 (Ref. 55)
- IAEA Safety Reports Series No. 82 (Rev. 2), "Ageing Management for Nuclear Power Plants: International Generic Ageing Lessons Learned (IGALL)," issued 2024 (Ref. 56)
- IAEA Safety Standard Series No. SSG-74, "Maintenance, Testing, Surveillance and Inspection in Nuclear Power Plants," issued 2023 (Ref. 57)
- IAEA Safety Reports Series No. 62, "Proactive Management of Ageing for Nuclear Power Plants," issued 2009 (Ref. 58)

C. STAFF REGULATORY GUIDANCE

In 10 CFR 50.46a(c)(1)(i), the NRC requires that entities representing existing plants demonstrate the applicability of the TBS to their facility. Analogously, 10 CFR 50.46a(c)(2) requires that entities representing new plants demonstrate why the proposed reactor design is similar to that of existing plants. This analysis must also include a proposed TBS and a justification that the proposed TBS is consistent with the 10 CFR 50.46a technical basis. The guidance in this section can be used by both new and existing plants to demonstrate the applicability of the NUREG-1829 and NUREG-1903 analyses to their plants. Such demonstration is sufficient for licensees with existing plants to demonstrate the applicability of the TBS to their facilities.

For new plants, demonstrating the adequacy of the NUREG-1829 and NUREG-1903 analyses satisfies the requirement that their reactor design be similar to the designs of existing plants. Additionally, new plants can use the results of the plant-specific evaluations described in this guidance as part of the technical basis for developing a proposed TBS and justifying the determination that this TBS is consistent with the 10 CFR 50.46a technical basis. Other plant-specific considerations when determining a plant-specific TBS are, however, not within the scope of this guidance.

The initial application must also address the impact of proposed plant changes on the generic or plant-specific TBS applicability as stipulated in 10 CFR 50.46a(c)(1)(i) for existing plants and 10 CFR 50.46a(c)(2) for new plants. In 10 CFR 50.46a(d)(4), the NRC requires that an entity perform an evaluation of all subsequent planned facility changes and must not implement any facility change that would invalidate the evaluation demonstrating the applicability of the TBS. The process submitted in accordance with 10 CFR 50.46a(c)(1)(v) allows subsequent plant changes to be implemented without prior NRC approval after the agency has approved the approach, methods, and decision-making process used to evaluate the continued applicability of the TBS, presuming that such changes do not invalidate the continued applicability of the TBS under 10 CFR 50.46a(h)(1)(iii). Alternatively, under 10 CFR 50.46a(h)(2), subsequent plant changes are to be submitted in a request for NRC review and approval. In 10 CFR 50.46a(h)(2)(v), the NRC requires that this application contain information demonstrating that the proposed change will not significantly increase the LOCA frequencies or invalidate the evaluation demonstrating the applicability of the TBS to the entity's facility.

Guidance is provided for evaluating the effects of plant changes on the applicability of both the generic TBS for existing plants and the plant-specific TBS for new plants. These methods are considered acceptable for evaluating these effects as part of the initial application required by 10 CFR 50.46a(c)(1)(i) or 10 CFR 50.46a(c)(2), as applicable. This guidance can also be used to satisfy the 10 CFR 50.46a(d)(4) requirements for evaluating subsequent planned facility changes consistent with the requirements in 10 CFR 50.46a(h)(1)(iii) or 10 CFR 50.46a(h)(2)(v), as applicable, for implementing these plant changes. DG-1426 provides guidance on the general approach for conducting the required risk-informed evaluation process and complying with the 10 CFR 50.46a(h) requirements.

C.1 NUREG-1829 Applicability

The evaluation of the plant-specific applicability of the NUREG-1829 generic LOCA frequency estimates should demonstrate that the entity is adhering to acceptable aging management practices, that the entity is implementing an adequate leak detection program, and that the plant-specific attributes are not significantly different from the generic considerations used with NUREG-1829. While the following sections describe several options to demonstrate applicability, entities can leverage existing programs and/or requirements to demonstrate applicability of the NUREG-1829 results. These items include the following:

Aging management programs (C.1.1) that have been approved under LR or SLR (no new justification or NRC review needed)

Leak detection programs (C.1.2) that conform to RG 1.45, Revision 1 (Ref. 10) (no new justification or NRC review needed)

LBB methods (C.1.3.1) that have been approved by the NRC⁷ (no new justification or NRC review needed)

An inspection program (C.1.4) provides assurance that unexpected degradation mechanisms that could invalidate the basis for the TBS will be identified (plant-specific justification and NRC review needed, unless the NRC approves generic industry methods)

Additional details pertaining to each of these considerations follow.

C.1.1 Acceptable Aging Management Practices

Figure 1 provides a schematic describing an acceptable method for determining the applicability of the NUREG-1829 results to a specific plant. Licensees for existing plants can use any of the following three options while entities with new plants can employ the section C.1.1.3 option for satisfying this portion of the NUREG-1829 applicability evaluation.

C.1.1.1 Evaluation Option I: License Renewal of Subsequent License Renewal Approval

This option is applicable for 10 CFR 50.46a entities that have been approved for LR or SLR and allows these entities to credit LR or SLR approval as a basis for demonstrating the adequacy of existing AMPs.

C.1.1.2 Evaluation Option II: First License Renewal Submittal

This option is applicable for 10 CFR 50.46a entities that have submitted their first LR application, but the NRC has not approved the application for the LR period. This option allows the entity to reference and credit the AMPs that have been submitted for approval as a basis for demonstrating the adequacy of their proposed AMPs. Such entities can wait to adopt their NRC-approved AMPs upon entering the LR period before implementing 10 CFR 50.46a. Alternatively, such entities can adopt the proposed AMPs that are applicable to the PLP and RCPB components before LR approval with the stipulation that any modifications in these AMPs resulting from NRC approval be adopted once the final safety evaluation report has been released.

C.1.1.3 Evaluation Option III: Alternative Evaluations

The 10 CFR 50.46a entities should demonstrate that they have adopted appropriate aging management practices for their PLP and RCPB components. An acceptable approach would demonstrate that either existing programs or proposed enhancements to existing programs ensure a reliable and adequate aging management program for their PLP and RCPB components.

One acceptable way of conducting this demonstration is to compare their existing programs for those PLP and RCPB components with those in the GALL or GALL-SLR Report and justifying the acceptability of any associated deviations. This report addresses the applicable inspection and mitigation

⁷ The NRC has approved LBB only for PWRs. BWRs may find it advantageous to consider it for implementation of 10 CFR 50.46a as well as to enable other plant changes.

activities associated with age-related degradation and describes applicable time-limited aging analysis to be performed on susceptible components during the LR period. The GALL Report documents the NRC staff's basis for determining which existing industry programs are adequate without modification and which existing programs should be augmented for LR.

Augmenting the existing programs may be needed if the materials, fabrication methods, operating environments, loading conditions, or inspection programs are substantially different than in existing LWR plants, for which the GALL and GALL-SLR Reports were written. A careful evaluation of plant-specific operating experience to date and of similarly designed plants as well as a comparison with comparable LWR operating experience are essential components of any evaluation to either demonstrate adequacy of the existing aging management program or provide a basis for proposed augmented programs. New plants with little operating experience should also consider international operating experience for similarly designed plants.

C.1.2 Adequate Leak Detection

In 10 CFR 50.46a(c)(1)(vii), the NRC requires a written evaluation as part of the application to implement 10 CFR 50.46a that demonstrates how the leak detection program in place at the facility satisfies the criteria in 10 CFR 50.46a(d)(2) to identify, monitor, and quantify leakage to ensure that leaking primary pressure boundary components do not result in adverse safety consequences that are larger than the TBS. There are two acceptable options for demonstrating that the leak detection program is adequate.

C.1.2.1 Option I: Demonstrate Adherence to Regulatory Guide 1.45

The entity exercising this option should describe the reactor coolant leakage detection methods and demonstrate adherence with the RG 1.45, Revision 1 (Ref. 10) regulatory positions. Any deviations from these positions should be adequately justified such that the objectives of RG 1.45, Revision 1 are achieved.

C.1.2.2 Option II: Demonstrate Compliance with General Design Criterion 30 and 10 CFR 50.46a(d)(2) Criteria

The entity exercising this option should describe the reactor coolant leakage detection methods and demonstrate how these methods comply with both the GDC 30 requirements "for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage" and the 10 CFR 50.46a(c)(1)(vii) requirement that the facility's leak detection program satisfy the criteria in 10 CFR 50.46a(d)(2) to identify, monitor, and quantify leakage to ensure that adverse safety consequences do not result from leaking primary pressure boundary components that are larger than the TBS.

C.1.3 Plant Specific Analyses

In this part of the evaluation, the entity should demonstrate that either the effects of each individual unique plant attribute or the combined effects of all unique plant attributes do not result in increases in the NUREG-1829 generic LOCA frequency estimates. Important plant-specific attributes to consider are related to the materials and fabrication methods, applied loading, geometry and configuration, service environment, and maintenance and AMPs associated with the PLP and each RCPB component. Licensees for existing plants should largely be able to leverage existing analyses and programs in this evaluation, while entities with new LWR plants should more comprehensively assess differences between their plants and the existing BWR and PWR plants considered in the NUREG-1829

analysis. Both existing and new plants need to assess plant-specific attributes associated with their PLP systems that are larger than the TBS and develop an NRC-approved, risk-informed PLP inspection sample as stipulated in 10 CFR 50.46a(b)(3) and 10 CFR 50.46a(d)(5). New plants will also need to assess plant-specific attributes associated with their RCPB components that are larger than the TBS. This guidance provides three acceptable options for demonstrating that the plant-specific PLP systems are appropriately representative of the generic PLP population used as the basis for the NUREG-1829 LOCA frequency estimates. Guidance is also included for an acceptable RCPB component evaluation for new plants and development of an NRC-approved, risk-informed PLP inspection for all plants.

C.1.3.1 Option I: Credit Existing or Conduct New Leak-Before-Break Evaluation of Primary Loop Piping Systems

Both existing and new plants can credit approved LBB evaluations for their PLP systems, presuming that they have been updated, as required, to address aging effects over the current licensing period. SRP Section 3.6.3 describes one acceptable method for conducting such analyses.

C.1.3.2 Option II: Conduct Probabilistic Fracture Mechanics Evaluation of Primary Loop Piping Systems

Both existing and new plants can perform PFM evaluations to demonstrate that their PLP systems have an extremely low probability of rupture (i.e., less than 10^{-6} /yr for the system), such that they comply with GDC 4. RG 1.245 describes an acceptable method for preparing and conducting such analyses. This analysis can credit the impacts of plant-specific inspections conducted under the entity's NRC-approved ISI program and inspections performed to satisfy the 10 CFR 50.46a(b)(3) requirements.

C.1.3.3 Option III: Conduct Alternative Evaluation of Primary Loop Piping Systems

Both new and existing plants can choose to directly address plant-specific attributes associated with their PLP systems. Such an evaluation should consider the plant-specific materials; fabrication practices; loading sources, frequencies, and magnitudes; geometries and system configurations; material and component degradation; and aging management. The evaluation should identify unique aspects of these attributes compared to the generic considerations used in NUREG-1829 and assess their impact on the NUREG-1829 LOCA frequencies and the applicability of the TBS.

C.1.3.4 Conduct Reactor Coolant Pressure Boundary Component Evaluation (New Plants Only)

A new plant will also need to evaluate the applicability of the NUREG-1829 results associated with other RCPB components that could lead to a LOCA that is greater than the TBS. As with the alternative evaluation described in section C.1.3.3, such an evaluation should address the plant-specific materials; fabrication practices; loading sources, frequencies, and magnitudes; geometry and configuration; material and component degradation; and the aging management for each RCPB component. The evaluation should identify any unique aspects of these attributes compared to the generic considerations for RCPB components considered in NUREG-1829 and assess the impacts of these differences on the NUREG-1829 LOCA frequencies and the applicability of the TBS.

C.1.4 Develop Acceptable Primary Loop Piping Inspection Sample

Both existing and new plants will need to develop an acceptable PLP sample population. For existing plants, per 10 CFR 50.46a(b)(3), an NRC-approved, risk-informed sampling of the similar metal piping circumferential welds in a PWR and the Category A welds (in accordance with BWRVIP-75-A) in a BWR is required before implementation of 10 CFR 50.46a and in every subsequent ISI interval. A 10

percent sampling of these welds is an acceptable risk-informed sample. The NRC would also consider a fleet wide inspection program. The sampling must include those applicable circumferential welds with the highest failure potential, defined as the unique, plant-specific combination of lowest toughness and susceptible materials and highest applied and residual loads such that these weld locations are the most likely to rupture. New plants should similarly identify the welds with the highest potential of failure in their PLP systems for welds not expected to have an active degradation mechanism, such that an appropriate sampling of the total PLP population is under their ISI program. For both new and existing plants, PLP welds within this population that are already being inspected under an existing NRC-approved ISI program can be credited for meeting this sampling requirement.

C.2 NUREG-1903 Applicability

C.2.1 Overview of NUREG-1903 Considerations

The plant-specific applicability and implications of the NUREG-1903 analyses demonstrate that the seismic risk associated with direct failures of degraded PLP systems and RCPB components, as well as the risk associated with indirect seismic failures in these SSCs, is significantly less than the frequency associated with the TBS. Acceptable methods for demonstrating the low likelihood of direct seismic failures are provided in sections C.2.4 and C.2.5, while section C.2.6 addresses indirect seismic failures. Several different options, with varying degrees of conservatism and rigor, are provided for conducting the direct seismic failure analysis. If the criteria associated with these options cannot be met, then the generic TBS provided in 10 CFR 50.46a(a)(9) is not applicable, and entities have the option to develop plant-specific TBS values. Additional details pertaining to the considerations associated with evaluating the direct and indirect seismic risk contributions follow.

C.2.2 General Approach

The general approach first requires a determination of the plant's limiting locations, or those locations having the highest risk of failure due to seismic loading (section C.2.3). Once the limiting locations are identified, there are two paths to demonstrate plant-specific applicability.

- 1) Section C.2.4 contains the requirements for demonstrating NUREG-1903 applicability at limiting locations that are either part of the entity's existing ISI program or have been added to the ISI program to satisfy 10 CFR 50.46a(b)(3) requirements.
- 2) For limiting locations not included in the ISI program or when significant flaws exist that cannot be appropriately dispositioned, an entity needs to perform an additional analysis to demonstrate that the failure frequency associated with those locations is commensurate with the NUREG-1903 evaluation and results. Several options can be chosen for this additional analysis, including a bounding analysis that leverages existing NUREG-1903 results, a plant-specific deterministic analysis, or a probabilistic analysis. Section C.2.5.1 provides options for determining the stresses used in these analyses while section C.2.5.2 provides options for selecting material properties. Sections C.2.5.3.1 and C.2.5.3.2 describe the bounding and plant-specific deterministic analyses, respectively, while section C.2.5.3.3 describes an acceptable method for performing a probabilistic analysis.

C.2.3 Limiting Location Selection

The scope of the analysis is the PLP piping, which means all piping systems having an inner diameter that is greater than the TBS. Next, the entity should identify, and provide a basis for, all limiting locations that are represented by the combination of high component stresses and low material fracture

toughness, accounting for aging effects over the licensing period. Susceptibility to service-induced cracking should be an additional consideration if the high stress and low fracture toughness combination among several locations are similar. Multiple possible limiting locations may need to be evaluated if the limiting location is not obvious or, for inspected locations, if the ISI methods applied at those locations have different flaw depths that can be reliably detected. The entity should strive to include all limiting locations within its ISI program while meeting the requirement of 10 CFR 50.46a(b)(3).

C.2.4 Applicability Demonstration Through the In-service Inspection Program

For those limiting locations that are part of the ISI program (either the existing program or part of the sample discussed in section C.1.4), the plant-specific acceptability of NUREG-1903 can be demonstrated through successful application of that program. Initially, to demonstrate that the ISI methods used will reliably detect flaws before they reach the critical size, the entity should demonstrate that the ISI program is acceptable by doing the following:

- (1) Describe the applicable ISI method and quality assurance provisions.
- (2) Demonstrate that the ISI method is qualified for length and, preferably, depth sizing according to the requirements of ASME Code, Section XI, Appendix VIII, or other applicable NRC-approved requirements.
- (3) Demonstrate that the ISI method provides reasonable assurance that flaw sizes equivalent to the detectability limits can be reliably detected in practice.

During the implementation of the ISI program, the NUREG-1903 results remain applicable at these locations as long as no indications exceed IWB-3500 requirements. Existing⁸ or new indications exceeding IWB-3500 requirements should be dispositioned in accordance with IWB-3600 requirements, with an additional requirement that the indications do not lead to component failure upon application of the plant-specific mean 10^{-6} /yr seismic stress. A structural factor of 1 should be used in this analysis. The seismic stress for this analysis is to be determined in accordance with section C.2.5.1, and materials properties should be determined as indicated in section C.2.5.2. For limiting locations inspected without an ISI technique qualified for depth sizing (e.g., circumferential welds on CASS components), the flaw depth in this analysis should be assumed to be through wall. If the IWB-3600 requirements cannot be met with this analysis, then a PFM analysis (section C.2.5.3.3) can be performed to demonstrate acceptability, that the indications can be repaired, or that the component can be replaced.

C.2.5 Applicability demonstration through analysis

C.2.5.1 Component Stresses

For entities performing an analysis to demonstrate the acceptability of NUREG-1903 or to disposition indications found during inspections as described in section C.2.4, the entity needs to determine the stresses at the limiting locations. The NRC staff considers any of the three options described in the following sections to be acceptable for determining the component stresses.

8 “Existing indications exceeding IWB-3500 requirements” means previously mitigated locations as indicated in ASME Code Case N-770 for PWRs or BWRVIP-75-A for BWRs having existing indications that were not repaired before the application of the mitigative technique.

C.2.5.1.1 Option I: Use NUREG-1903 Results

This option is available for entities whose plants were analyzed in NUREG-1903, assuming that the following three conditions are met:

- (1) The critical PLP locations reported in the plant's LBB submittal are still applicable after accounting for cracking susceptibility and age-related toughness degradation at these locations. This evaluation should address the effects of material property uncertainty when identifying the critical PLP locations.
- (2) The normal operating and SSE stresses in the LBB analysis are either accurate or conservative at the limiting locations.
- (3) The site-specific seismic hazard curve and UHS contained in the plant's SHSR (Ref. 41) are either conservative or represented by the applicable seismic hazard curve and UHS (i.e., from NUREG-1488) as extended to a 10^{-6} /yr probability of exceedance in NUREG-1903.

If these conditions are satisfied, the entity can use the plant-specific total stresses developed in the NUREG-1903 analysis throughout the remainder of this analysis. If additional limiting locations (section C.2.3) are identified that were not analyzed in NUREG-1903, those will require separate evaluation using one of the other methods discussed in section C.2.

C.2.5.1.2 Option II: NUREG-1903 Scale-Factor Method

This option uses the scale factor method described in NUREG-1903 to determine the total component stress at each limiting location. The entity should first develop the seismic hazard information by determining the site-specific seismic hazard curve and UHS using the current SHSR information for the site out to a 10^{-6} /yr probability of exceedance. This estimate should address uncertainties and, if applicable, account for any new information that impacts the validity of the existing hazard estimates. Next, at each limiting location, the entity should determine the axially oriented, normal operating and SSE stresses, as described for Service Level A and D loadings, respectively, in ASME Code, Sections III and XI. Finally, the entity should extrapolate the SSE stresses to seismic stresses representative of a 10^{-6} /yr probability of exceedance by directly calculating the scale factor, as described in NUREG-1903.

C.2.5.1.3 Option III: Direct Analysis

This option allows the entity to determine the component stresses at the limiting locations by direct analysis. For this analysis, the entity should first determine the axially oriented, normal operating stresses at the limiting locations, as described for Service Level A loadings in ASME Code, Sections III and XI. Then the entity should determine the seismically induced component stresses by completing the following steps:

- (1) Develop an updated, representative site-specific hazard curve and ground motion UHS for a 10^{-6} /yr probability of exceedance based on the latest SHSR information.
- (2) Model the site-specific foundation properties for the 10^{-6} /yr seismic hazard.
- (3) Construct a reactor building dynamic model that includes all major structures (i.e., containment, internal structure, and any other major structures supported from the common foundation) and the PLP.
- (4) Perform a soil-structure interaction analysis for the given seismic input motion using applicable

soil or rock and structural models.

- (5) Address modeling and input uncertainties and their effects on the PLP stresses at the limiting locations.

C.2.5.2 Material Properties

Entities performing an analysis to demonstrate the acceptability of NUREG-1903 or to disposition indications found during inspections in accordance with section C.2.4 require material properties for this analysis. One acceptable approach is to use the properties associated with either the carbon-steel base and weld materials, or stainless-steel SAW material used in NUREG-1903 by demonstrating that these properties are conservative (i.e., lower than) or representative of the actual plant-specific properties at the limiting locations. Alternatively, the entity can develop representative or conservative plant-specific material properties based on ASME Code, generic, or measured properties. The acceptability of the NUREG-1903 properties or the appropriateness of the developed properties can be demonstrated by completing the following steps:

- (1) Determine the material properties at the operating temperature at each limiting location.
- (2) Account for any age-related degradation of the strength, toughness, and, if applicable, crack growth rate properties.
- (3) Consider effects on these material properties caused by the elevated loading rates associated with a seismic event.
- (4) Assess the effects of uncertainty and variability in material properties.

If ASME Code or other generic properties are used for this plant-specific assessment, the entity should demonstrate that they conservatively represent the limiting material properties after addressing effects (2), (3), and (4) above.

C.2.5.3 Surface Flaw Analysis

The NRC staff considers either of the first two following options to be acceptable for determining the critical surface flaw sizes consistent with the approach used in NUREG-1903, while the third, probabilistic, option can be used to demonstrate that the seismic failure risk of the PLP system is acceptable.

C.2.5.3.1 Option I: NUREG-1903 Bounding Analysis

If the material properties used in the NUREG-1903 analysis appropriately represent the plant-specific material properties (section C.2.5.2), the entity may be able to leverage the NUREG-1903 results. To directly use the NUREG-1903 results, the entity must also demonstrate that the axially oriented, combined normal operating plus 10^{-6} /yr seismic stresses (i.e., total stress, section C.2.5.1) with seismic scale and elastic stress correction factors are less than 35 kilopounds per square inch (ksi), which are the highest stresses evaluated in NUREG-1903. If the total stress is less than 35 ksi at each limiting location, then the NUREG-1903 results are applicable to the plant.

C.2.5.3.2 Option II: Plant-Specific Deterministic Analysis

If the total stress calculated in section C.2.5.1 is greater than 35 ksi or if the plant-specific material properties determined in section C.2.5.2 are not appropriately bounding, or representative of, the

NUREG-1903 material properties, analysis is needed to satisfy the NUREG-1903 applicability. In this analysis, the critical flaw size at each limiting location is determined using the stresses and material properties determined in sections C.2.5.1 and C.2.5.2, respectively. The principal steps in the analysis are as follows:

- (1) Combine the normal operating and 10^{-6} /yr seismic stresses from section C.2.5.1 to determine the total stress associated with the 10^{-6} /yr seismic event.
- (2) Apply the NUREG-1903 plasticity correction factor, if appropriate, to account for plasticity within the component under seismic loading.
- (3) Assume a flaw length of $\theta/\pi = 0.8$ (i.e., 80 percent of the component circumference) with the flaw oriented circumferentially in the worst possible location relative to the bending plane.
- (4) Determine the NUREG-1903 Z-factor correction for the limiting material(s) and use this Z-factor with the limit-load solution to determine the critical flaw depth using the direct analytical methods presented in ASME Code, Section XI, Appendix C, for elastic-plastic failure (Article IWB-3640), but by setting the ASME Code structural factor to 1.0.

Alternatively, the entity can determine the critical flaw size using EPFM predictions of component failure without applying the Z-factor approach. In this analysis, the entity should use the applied stresses determined in section C.2.5.1 and the material properties determined in section C.2.5.2 and follow steps (1)–(3) of this section when setting up the analysis. If the critical flaw depth exceeds 25 percent of the wall thickness at each limiting location, the NUREG-1903 results are applicable to the plant.

C.2.5.3.3 Option III: Plant-Specific Probabilistic Analysis

An approved PFM analysis is an alternative approach for demonstrating that the seismic risk associated with direct failures of degraded PLP systems and RCPB components is significantly less than the frequency associated with the TBS. The PFM submittal for NRC review of such an evaluation should be consistent with RG 1.245. An acceptable approach follows:

- (1) The determination of the PFM analysis scope and the limiting locations, as described in section C.2.3, should be identical to the deterministic analysis.
- (2) Determining component stresses for the PFM analysis should follow a similar approach as described in section C.2.5.1.
 - a. An applied stress distribution should be used for each limiting location and the Option 1, Option 2, or Option 3 approach can be used as a basis for the mean value (10^{-6} /year) of the stress distribution, with appropriate justification, while explicitly addressing the associated uncertainties when determining the remaining characteristics of the applied seismic stress distribution.
- (3) The PFM analysis should use property distributions for material strength, crack growth rate associated with applicable degradation mechanisms, and fracture toughness.
 - a. These distributions can be based on either generic or plant-specific material properties, but the representativeness of these properties to the plant-specific material properties should be justified.

- b. Effects of fabrication techniques on the property distributions should be considered and correlations among strength, crack growth rate, and toughness distributions should be addressed and accounted for in the analysis, if appropriate.
 - c. Effects of dynamic rate and cyclic loading during the seismic event and thermal aging effects on the properties should be considered, as in the NUREG-1903 analysis, such that the properties are applicable over the plant's intended licensing period.
- (4) An appropriate deterministic or probabilistic failure criterion should be selected.
 - a. A Z-factor criterion (section C.2.5.2) is one acceptable criterion.
 - b. Other failure criteria (e.g., failure assessment diagram, tearing instability) may also be acceptable.
 - c. The basis for the criterion should be appropriately justified.
- (5) An initial flaw distribution should be assumed and related to either the known flaw distribution or a distribution corresponding to the flaw detectability size for the nondestructive examination method used to inspect the limiting locations. If only a depth distribution can be justified, an initial aspect ratio of flaw length to depth of 6 can be used.
- (6) Applicable leak detection limits with known uncertainty should be applied to the analysis.
- (7) The analysis should be run for 80 years, and the probability of failure for the piping system containing the limiting locations should be less than $10^{-6}/\text{yr}$.
- (8) Sensitivity studies should be conducted on both seismic stress and the flaw length distributions, in addition to other sensitivity analyses, in accordance with RG 1.245, with the probability of failure increasing no more than two orders of magnitude.
- (9) These analyses can be combined with those in section C.1.3.2 if that option is chosen.

C.2.6 Seismically Induced Risk of Indirect Primary Loop Piping or Reactor Coolant Pressure Boundary Component Failures

One acceptable way to demonstrate that the risk of seismically induced indirect PLP system or RCPB component failure is significantly less than the frequency associated with the TBS is to perform a risk-informed evaluation as described in DG-1426, which describes the process and provides acceptance guidelines for performing this analysis. Often, plant sites located in high seismic risk zones employ a full-scope seismic PRA approach to identify their seismic risk insights and associated vulnerabilities. The assessment of seismic risk associated with indirect piping failure leading to LOCA scenarios is one part of this analysis. If a plant-specific seismic PRA is used, it should comply with RG 1.200, ASME/ANS RA-Sa-2009, and ANSI/ANS-58.21. The EPRI Seismic Probabilistic Risk Assessment Implementation Guide (Ref. 50) provides guidelines for performing state-of-the-art PRAs that are acceptable for satisfying the aforementioned standards and guidance. Methods other than seismic PRAs are also acceptable for performing this analysis if their use is appropriately justified. Further, these methods can be efficiently implemented based on the results of past seismic assessments (e.g., the seismic margin assessment in NUREG/CR-4334) to the extent possible, minimizing a need for new additional analyses.

Whether a PRA or non-PRA approach is employed, the analyses should incorporate the most up-to-date plant-specific seismic hazard information. Additionally, plant-specific component and support

fragilities should appropriately account for any age-related degradation. Approaches using a seismic PRA should demonstrate that the plant's baseline risk associated with indirect seismic failures contributing to a LOCA that is larger than the TBS is less than 10^{-6} /yr. Non-PRA methods should demonstrate that appropriate margin for indirect failures of the PLP and RCPB components exists and that this risk is a minor contributor to the plant's total seismic margin, or risk.

C.3 Plant Changes That May Affect Loss-of-Coolant Accident Frequencies

Regulations in 10 CFR 50.46a(h)(1)(iii) and 10 CFR 50.46a(h)(2)(v), as applicable, require that the proposed plant changes do not significantly increase LOCA frequencies or invalidate the evaluation demonstrating the applicability of the TBS to the entity's facility. This section provides one approach for demonstrating that there is no significant impact of the proposed plant changes such that the TBS remains applicable after implementing those changes. The following general considerations apply to the analyses discussed in this section:

- (1) The evaluation scope should consider potential impacts on the LOCA frequencies associated with both direct and indirect failures of the PLP and the RCPB components that could lead to a LOCA that is greater than the TBS.
- (2) Failures under normal operational loading, design-basis and other accident loading, and rare seismic loading, as in the NUREG-1903 analysis, should be addressed.
- (3) Effects of age-related degradation should be considered.
- (4) A risk-informed evaluation should demonstrate that the plant changes do not cause a significant increase in the frequency of LOCAs with sizes greater than the TBS.
 - a. The evaluation should document the assumptions and approach used to perform the analysis.
 - b. Any potential impacts of the proposed plant changes that could affect causal phenomena or attributes associated with such LOCAs should be described.
 - c. The evaluation of the significance of any such relevant impacts should be documented, along with the acceptance criteria used to assess the significance. The basis for the acceptance criteria should be justified, as appropriate.
 - d. The evaluation should demonstrate that the changes satisfy the risk-informed requirements in 10 CFR 50.46a(h).
- (5) The performance monitoring program that will be used to evaluate changes in plant attributes, characteristics, or responses that may impact LOCA frequencies (e.g., accelerated material degradation) should be described. This description should include the monitoring parameters and their acceptance criteria and provide the justification that both the parameters and criteria are appropriate for demonstrating that the plant change has not significantly affected LOCA frequencies.

DG-1426 contains more details on the guidance for developing and implementing the risk-informed evaluation process used to assess the total risk significance associated with proposed plant changes.

C.3.1 Plant Changes That May Affect Direct Failure Frequencies

Components of an acceptable analysis of the impacts of proposed plant changes on direct failure frequencies should demonstrate the continued applicability of the NUREG-1829 and NUREG-1903 analyses as a proxy for demonstrating the continued applicability of the TBS. This portion of the evaluation should demonstrate that the proposed plant changes under 10 CFR 50.46a do not significantly alter any inspections associated with the limiting locations, if applicable, and the critical variables that affect the plant's PLP and RCPB-component LOCA frequencies. These critical variables include materials, fabrication methods, service environment, applied loading, age-related degradation mechanisms, geometry and configuration, and the maintenance and mitigation associated with each potential failure location to demonstrate the continued applicability of NUREG-1829 and NUREG-1903. Included below are two acceptable options for demonstrating continued NUREG-1829 applicability and one acceptable approach for demonstrating the continued applicability of the plant-specific NUREG-1903 analyses.

C.3.1.1 Option I: Effects on NUREG-1829 Variables

This option explicitly evaluates the impacts stemming from proposed plant changes related to the materials, service environment, loading history, age-related degradation mechanisms, geometry and configuration, and maintenance and mitigation. If it can be demonstrated that the proposed changes do not significantly affect these variables, and that degradation is not accelerated and LOCA frequencies potentially do not increase, then the proposed changes are acceptable. In addition to addressing the considerations in section C.3, the entity, in this analysis, should perform and document the following steps:

- (1) Describe the approach used in the analysis.
- (2) Identify whether, and describe how, the proposed plant changes affect either the materials, service environment, loading history, age-related degradation mechanisms, geometry, and configuration, or maintenance and mitigation.
- (3) Assess the effects of the proposed plant changes on the emergence of new, or previously unobserved, degradation mechanisms.
- (4) Assess the significance of any identified effects.
- (5) Describe the performance monitoring program used to provide assurance that LOCA frequencies are not increasing.

The RS for EPU (Ref. 52) provides additional guidance related to the aspects of these analyses that the entity should consider.

C.3.1.2 Option II: Review Standard for Extended Power Uprates

This option uses guidance and criteria based specifically on the RS for EPU (Ref. 52) to evaluate the likelihood of changes in the direct failure LOCA frequency resulting from the proposed plant changes. While power uprates are submitted separately for NRC review, the guidance in this section could be used to evaluate plant changes other than power uprates. Only the guidance and criteria related to topics that could potentially impact the PLP and RCPB components are applicable. Specifically, this analysis should address potential impacts on the following topical areas: reactor vessel materials surveillance program; pressure-temperature limits and upper-shelf energy; RCPB materials; pressurized thermal shock; LBB; pressure-retaining components and component supports; for PWRs, the chemical and volume control

system; and, for BWRs, the reactor water cleanup system. If the entity can demonstrate that the proposed plant changes do not significantly affect these topical areas, and that degradation is not accelerated and LOCA frequencies potentially do not increase, then the proposed changes are acceptable.

In addition to addressing the considerations in section C.3, the entity should perform and document the following steps when implementing this option:

- (1) Describe the approach used in each separate topical area evaluation.
- (2) Describe the relevance of the proposed plant changes to each topical area.
- (3) Determine the significance of the proposed plant changes, as applicable, for each topical area.
- (4) Assess the effects of the proposed changes on the emergence of new, or previously unobserved, degradation mechanisms as part of steps (2) and (3).
- (5) Describe the performance monitoring program used to provide assurance that the proposed plant changes are not significantly negatively impacting these topical areas.

The RS for EPU (Ref. 52) provides more detailed guidance associated with each topical area evaluation. The RS identifies related SRP sections and applicable regulations addressed by each evaluation and provides other related review guidance.

C.3.1.3 Evaluate Effects on NUREG-1903 Analyses

The NUREG-1903 applicability determination (section C.2) relies on the entity's ISI program (section C.2.4) or analysis (section C.2.5) to demonstrate plant-specific applicability. For limiting locations addressed by the ISI program, the entity should do the following:

- (1) Verify that the proposed changes do not impact or alter the inspections of the limiting locations.
- (2) Determine whether the proposed changes increase material degradation rates or degrade component inspectability, such that it significantly affects the ability of the ISI program to detect flaws to support the IWB-3500 or IWB-3600 disposition of any indications present.
- (3) If any potential effects on (1) and (2) above are identified, include a discussion on how these effects impact the requirements of 10 CFR 50.46a(b)(3) and the analysis in section C.2.5, if applicable.

For limiting locations addressed by analysis (section C.2.5), the evaluation of the effect of the proposed plant changes should consider their effects on the principal aspects of that analysis (i.e., plant-specific normal operating and seismic loads and material properties) to provide assurance that the surface flaw analysis remains acceptable. In addition to addressing the considerations in section C.3, the entity should perform and document the following steps when conducting this evaluation:

- (1) Identify and assess the significance of the proposed changes that may increase the total component stresses (section C.2.5.1) at each limiting PLP location (section C.2.3).
- (2) Identify and assess the significance of the proposed changes that may decrease the materials' strength or fracture toughness or increase the crack growth rate of associated degradation mechanisms (section C.2.5.2) at the limiting PLP locations.

- (3) Identify and assess the significance of the proposed changes that may impact the surface flaw analysis results (section C.2.5.3) such that the acceptance criteria are no longer met.

C.3.2 Plant Changes That May Affect Indirect Failure Frequencies

The two topics that the entity should address in this portion of the analysis to demonstrate that LOCA frequencies developed in NUREG-1829 remain applicable to the plant after adopting the proposed plant changes are dynamic effects (section C.3.2.1) and missile protection (section C.3.2.2). This RG provides two acceptable options for this analysis. The first option uses the results of prior indirect failure analyses that show compliance with existing regulations. Under this option, the entity should evaluate the relevance and sufficiency of prior analyses to ensure that they adequately address impacts resulting from the proposed plant changes. If the prior analyses are not sufficient, the entity should supplement them with additional evaluation to demonstrate their continued acceptability. Alternatively, the second option allows for an explicit evaluation of the potential impacts of the proposed plant changes without relying on prior indirect failure analyses.

C.3.2.1 Impact of Plant Changes on Dynamic Effects

The dynamic effects associated with a pipe rupture in either primary pressure boundary piping that is smaller than the TBS or within a nonprimary pressure boundary system could challenge the integrity of the PLP and RCPB components. Dynamic effects include jet impingement loading, jet thrust loading, and pipe whip. The entity should assess relevant impacts of the proposed plant changes within such primary and nonprimary pressure boundary systems on the likelihood that these systems could fail, that the most likely failure locations could be altered, or that the consequences associated with their failure could increase.

The entity should first identify possible rupture locations and assess consequential dynamic effects accounting for the impact of the proposed plant changes. A principal consideration is an assessment of impacts of the proposed plant changes on systems and components that are susceptible to FAC and the adequacy of the entity's FAC program to predict the rate of material loss such that the component can be repaired or replaced with adequate margin before failure. The entity should then evaluate the impacts of postulated failures on the PLP and RCPB components to demonstrate that their structural integrity is not impaired to an unacceptable level because of dynamic effects. Effects on existing, or the need for additional, mitigation or performance monitoring measures should also be evaluated. This analysis should specifically address the effects on PLP and RCPB component supports because support failures could initiate subsequent primary pressure boundary failures. SRP Section 3.6.2 contains specific review criteria. In addition to addressing the considerations in section C.3, the entity's evaluation should describe and document the following aspects:

- (1) the criteria for defining pipe break and flaw locations and configurations,
- (2) the effects of the proposed plant changes on relevant FAC-susceptible components and systems, if applicable, and the adequacy of the FAC program to mitigate any effects,
- (3) pipe whip dynamic analyses, effects, and results, including the consideration of jet thrust and impingement forcing functions,
- (4) potential impacts on the structural integrity of PLP and RCPB components and their supports, and
- (5) the implementation of special programs, such as augmented ISI programs, or the use of special protective devices, such as pipe whip restraints, to mitigate dynamic effects.

C.3.2.2 Impact of Plant Changes on Missile Protection

Objectives of this evaluation are to demonstrate the adequacy of the PLP and RCPB component missile protection while also ensuring the low likelihood of internally generated (i.e., inside containment) missile sources. Therefore, one acceptable method for demonstrating that the proposed plant changes are acceptable is to show that they will not substantively affect missile sources, the likelihood of missiles, and missile protection of the PLP and RCPB components. The analysis approach should identify any changes in the missile protection measures arising from (or as part of) these proposed changes. Modifications to existing measures can be implemented to mitigate the additional risk of these types of failures arising from the proposed plant changes. In addition to addressing the considerations in section C.3, the entity's evaluation should describe and document the following aspects:

- (1) Identify potential missile sources among applicable pressurized components and systems and high-speed rotating machinery.
- (2) Identify additional missile sources (i.e., sources not identified in existing approved analysis) resulting from the proposed plant changes.
- (3) Assess the likelihood of missiles from these sources and describe any measures to decrease any increases in this likelihood arising from the proposed plant changes.
- (4) Demonstrate the adequacy of missile protection of the PLP and RCPB components, including modifications made to address any additional risk associated with the proposed plant changes.

C.3.2.3 Impact of Plant Changes on Loss-of-Coolant Accident Frequencies Greater Than the Transition Break Size Due to Seismically Induced Risk of Indirect Primary Loop Piping or Reactor Coolant Pressure Boundary Component Failures

Guidance is provided in section C.2.6 of this RG and DG-1426 for performing the initial analysis of the baseline plant risk associated with indirect seismic failures (i.e., external hazards or events in DG-1426) that could induce LOCAs greater than the TBS in PLP and RCPB components. The change in risk due to proposed plant changes enacted under 10 CFR 50.46a should be determined using risk assessment methods that are of sufficient technical acceptability to provide confidence in the risk estimates. DG-1426 provides guidance to assess the risk associated with changes made under 10 CFR 50.46a. For an entity with a self-approved risk-informed evaluation process, each individual plant change must result in, at most, a minimal increase in risk. For an entity without a self-approved risk-informed evaluation process, each individual plant change must result in, at most, a very small increase in the core damage frequency and large early release frequency, and the overall plant risk should remain small. Each plant change must also be evaluated to demonstrate that, subsequent to the plant change, adequate defense in depth is maintained, adequate safety margins are retained to account for uncertainties, and adequate performance-measurement programs are implemented to ensure the risk-informed evaluation continues to reflect actual plant design and operation. The cumulative effects of the proposed change and all previous plant changes should also be addressed as part of this assessment.

DG-1426 provides guidance for meeting the risk requirements in 10 CFR 50.46a. As the risk associated with indirect seismic failures is just a subset of the total plant risk, adhering to the guidance in DG-1426 is one acceptable way to demonstrate that the seismically induced indirect failure risk to the PLP or the RCPB components associated with the proposed plant changes is acceptable such that the TBS remains applicable.

D. IMPLEMENTATION

Licensees generally are not required to comply with the guidance in this regulatory guide. If the NRC proposes to use this regulatory guide in an action that would constitute backfitting, as that term is defined in 10 CFR 50.109, “Backfitting,” and as described in NRC Management Directive 8.4, “Management of Backfitting, Forward Fitting, Issue Finality, and Information Requests” (Ref. 59); affect the issue finality of an approval issued under 10 CFR Part 52, “Licenses, Certifications, and Approvals for Nuclear Power Plants”; or constitute forward fitting, as that term is defined in Management Directive 8.4, then the NRC staff will apply the applicable policy in Management Directive 8.4 to justify the action. If a licensee believes that the NRC is using this regulatory guide in a manner inconsistent with the discussion in this Implementation section, then the licensee may inform the NRC staff in accordance with Management Directive 8.4.

ABBREVIATIONS

AMP	aging management program
ANS	American Nuclear Society
ANSI	American National Standards Institute
a/t	normalized flaw depth
ASME	American Society of Mechanical Engineers
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
BWR	boiling-water reactor
BWRVIP	boiling-water reactor vessel internals program
CASS	cast austenitic stainless steel
CFR	<i>Code of Federal Regulations</i>
DG	draft guide
ECCS	emergency core cooling system
EPFM	elastic-plastic fracture mechanics
EPRI	Electric Power Research Institute
EPU	extended power uprate
FAC	flow-accelerated corrosion
GALL	generic aging lessons learned
GDC	general design criterion/criteria
ISI	in-service inspection
J-R Curve	a tool for evaluating material fracture toughness in the ductile region
ksi	kilopounds per square inch
LBB	leak before break
LLNL	Lawrence Livermore National Laboratory
LOCA	loss-of-coolant accident
LR	license renewal
LWR	light-water reactor
NRC	U.S. Nuclear Regulatory Commission
OMB	Office of Management and Budget
PFM	probabilistic fracture mechanics
PGA	peak ground acceleration
PLP	primary loop piping
PRA	probabilistic risk assessment
PRC/CS	pressure-retaining components and component supports
PTL	pressure temperature limits
PTS	pressurized thermal shock
PWR	pressurized-water reactor
RCPB	reactor coolant pressure boundary
RG	regulatory guide
RS	review standard
RCPBM	reactor coolant pressure boundary materials
RVMS	reactor vessel material surveillance program

RWCS	reactor water cleanup system
S_m	ASME design stress intensity allowable, Class 1 components
S_y	material yield strength
S_u	material ultimate strength
SAW	submerged arc weld
SCC	stress-corrosion cracking
SHSR	seismic hazard and screening report
SMAW	shielded metal arc weld
SLR	subsequent license renewal
SRM	Staff Requirement Memorandum
SRP	Standard Review Plan
SRP-LR	standard review plan-license renewal
SSC	systems, structures, and components
SSE	safe-shutdown earthquake
TBS	transition break size
UHS	uniform hazard spectra
USE	upper shelf energy
yr	year
Z-factor	ratio of the failure stress predicted from a limit-load calculation to the failure stress predicted using elastic-plastic fracture mechanics

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14 Copies of ANSI standards may be purchased from ANSI, 1819 L Street, NW, Washington, DC 20036, on their website at <http://webstore.ansi.org/>; telephone (202) 293-8020; fax (202) 293-9287; or email storemanager@ansi.org. Copies of ANS standards may be purchased from the ANS website (<http://www.new.ans.org/store/>); or by writing to: American Nuclear Society, 555 North Kensington Avenue, La Grange Park, Illinois 60526, U.S.A., Telephone 800-323-3044.

52. NRC, RS-001, Revision 0, “Review Standard for Extended Power Upgrades,” Washington, DC, December 2003 (ML033640024).
53. NRC, “Nuclear Regulatory Commission International Policy Statement,” *Federal Register*, Vol. 79, No. 132, July 10, 2014, pp. 39415–39418.
54. NRC, Management Directive (MD) 6.6, “Regulatory Guides,” Washington, DC.
55. International Atomic Energy Agency (IAEA), Safety Standards Series No. SSG-48, “Ageing Management and Development of a Programme for Long Term Operation of Nuclear Power Plants,” Vienna, Austria, 2018.¹⁵
56. IAEA, Safety Reports Series No. 82, Revision 2, “Ageing Management for Nuclear Power Plants: International Generic Ageing Lessons Learned (IGALL),” Vienna, Austria, 2024.
57. IAEA, Safety Standard Series No. SSG-74, “Maintenance, Testing, Surveillance and Inspection in Nuclear Power Plants,” Vienna, Austria, 2022.
58. IAEA, Safety Reports Series No. 62, “Proactive Management of Ageing for Nuclear Power Plants,” Vienna, Austria, 2009.
59. NRC, MD 8.4, “Management of Backfitting, Forward Fitting, Issue Finality, and Information Requests,” Washington, DC.

15 Copies of International Atomic Energy Agency (IAEA) documents may be obtained through their website WWW.IAEA.Org/ or by writing to the International Atomic Energy Agency, P.O. Box 100 Wagramer Strasse 5, A-1400 Vienna, Austria. Telephone (+431) 2600-0, fax (+431) 2600-7, or email at Official.Mail@IAEA.Org.

APPENDIX A

DETAILED INFORMATION FOR CONDUCTING PLANT-SPECIFIC ANALYSES USING THE NUREG-1903 APPROACH

This appendix contains information used in performing the seismic analyses in NUREG-1903, “Seismic Considerations for the Transition Break Size,” issued February 2008. The plant names are coded, and the codes have been changed for each unique table. Entities can contact the U.S. Nuclear Regulatory Commission for the plant-specific code identifiers.

The key tables consist of the following:

Table A-1	List of the 26 plants evaluated in NUREG-1903.
Table A-2	Scale factors, original design safe-shutdown earthquake (SSE) peak ground acceleration (PGA) values, Weibull fit coefficients to mean PGA probability curves, and calculated PGA values at seismic event with an exceedance frequency of 10^{-6} per year (yr) based on Lawrence Livermore National Laboratory seismic hazard curves and uniform hazard spectra (NUREG-1488, “Revised Livermore Seismic Hazard Estimates for Sixty-Nine Nuclear Power Plant Sites East of the Rocky Mountains,” issued April 1994).
Table A-3	Pressurized-water reactor (PWR) coolant piping information and calculated values by plant based on archival leak-before-break submittals, such as the following: • plant code number • segment of primary pipe loop used in evaluation (e.g., hot leg, cold leg) • pipe dimensions • materials at hypothetical flaw location (base metal and weld metals) • yield, ultimate, and flow stress using the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (ASME Code) values and mean or typical best estimate values from actual piping material data • elastic-plastic toughness correction factors (Z-factors) using both of the following: – ASME Code, Section XI, values – updated values from best estimate elastic-plastic fracture mechanics analyses to account for dynamic and cyclic corrections • normal operating temperature, pressure, and deadweight and thermal expansion stresses • design SSE stresses • calculated elastic stresses for a 10^{-6} per year (yr) seismic event (linearly scaled from seismic hazard curve information in table A-2)

- scale factor on original seismic design (accounts for conservatisms in original seismic analyses compared to more recent seismic analyses)
- calculated elastic stresses for a 10^{-6} /yr seismic event with scale factor correction
- 10^{-6} /yr stresses with additional nonlinear stress correction factor
- calculated surface-flaw depths as a function of flaw length at normal operating stress (N)+ 10^{-6} /yr corrected seismic stress (based on table A-2) using the following:
 - ASME Code analysis with code strengths
 - ASME Code analysis with typical actual strengths
 - best estimate analysis

Table A-1. List of the 26 Plants Evaluated in NUREG-1903

Arkansas 2
Beaver Valley 1
Braidwood 1
Braidwood 2
Byron 1
Byron 2
Callaway
Calvert Cliffs 1
Catawba 1
Catawba 2
Farley 1
Farley 2
Indian Point 2
McGuire 1
McGuire 2
Millstone 2
Millstone 3
Prairie Island 1
Seabrook 1
Sequoyah 1
Sequoyah 2
Shearon Harris 1
Turkey Point 3
Turkey Point 4
Watts Bar 1
Wolf Creek

Table A-2. Scale Factors, Original Design SSE PGA Values, Weibull Fit Coefficients to Mean PGA Probability Curves, and Calculated PGA Values at 10⁻⁶/yr Seismic Event

Site identification code	Original design SSE, g	Weibull fit parameters for mean PGA probability curves			SSE probability	PGA at 10 ⁻⁶ , g	Ratio of PGA to original SSE value 10 ⁻⁶ /ISSE
		scale	alpha	beta			
A	0.153	0.047	0.430	13.890	2.32E-05	0.633	4.135
B	0.100	0.062	0.384	12.300	5.85E-05	0.826	8.263
C	0.100	0.063	0.410	11.200	5.58E-05	0.675	6.754
D	0.100	0.068	0.395	12.280	6.37E-05	0.799	7.990
E	0.120	0.076	0.405	7.494	3.78E-05	0.574	4.785
F	0.100	0.081	0.424	11.340	7.24E-05	0.692	6.922
G	0.120	0.095	0.364	3.792	3.10E-05	0.526	4.384
H	0.104	0.098	0.391	15.270	9.65E-05	1.080	10.380
I	0.100	0.107	0.359	6.193	7.09E-05	0.780	7.798
J	0.120	0.120	0.389	18.130	1.04E-04	1.313	10.946
K	0.100	0.126	0.384	10.690	1.11E-04	0.991	9.914
L	0.104	0.127	0.379	15.100	1.24E-04	1.271	12.221
M	0.120	0.128	0.377	12.780	9.39E-05	1.165	9.709
N	0.120	0.130	0.380	13.050	9.63E-05	1.165	9.711
O	0.120	0.138	0.387	16.640	1.15E-04	1.327	11.062
P	0.200	0.154	0.470	16.560	4.85E-05	0.851	4.257
Q	0.240	0.163	0.423	9.204	2.24E-05	0.753	3.136
R	0.200	0.169	0.444	11.860	4.11E-05	0.799	3.993
S	0.153	0.175	0.441	12.280	7.62E-05	0.843	5.510
T	0.120	0.180	0.397	5.913	7.52E-05	0.685	5.711
U	0.200	0.181	0.462	15.200	5.34E-05	0.876	4.380
V	0.153	0.206	0.343	4.465	5.57E-05	0.922	6.024
W	0.153	0.232	0.447	11.240	9.12E-05	0.825	5.392
X	0.170	0.258	0.399	17.740	1.31E-04	1.600	9.411
Y	0.170	0.279	0.434	34.670	1.99E-04	2.071	12.181
Z	0.153	0.293	0.373	8.107	1.11E-04	1.193	7.799
AA	0.200	0.295	0.299	2.698	4.43E-05	1.196	5.979
AB	0.200	0.306	0.451	14.290	8.81E-05	1.032	5.161
AC	0.100	0.309	0.452	14.110	3.10E-04	1.022	10.222
AD	0.200	0.338	0.317	3.634	5.62E-05	1.248	6.239
AE	0.120	0.358	0.467	17.230	3.00E-04	1.122	9.351
AF	0.150	0.373	0.365	8.262	1.52E-04	1.403	9.355
AG	0.170	0.374	0.443	13.930	1.48E-04	1.129	6.644
AH	0.120	0.377	0.485	18.180	3.24E-04	1.062	8.853
AI	0.200	0.378	0.364	9.629	1.05E-04	1.564	7.819
AJ	0.200	0.384	0.423	28.750	1.96E-04	2.150	10.752
AK	0.170	0.391	0.379	9.503	1.36E-04	1.387	8.158
AL	0.230	0.397	0.452	15.550	9.35E-05	1.174	5.104
AM	0.170	0.402	0.448	15.290	1.70E-04	1.189	6.997
AN	0.153	0.432	0.456	15.920	2.26E-04	1.188	7.765
AO	0.153	0.435	0.441	13.840	2.09E-04	1.186	7.752
AP	0.180	0.438	0.458	15.170	1.61E-04	1.142	6.342
AQ	0.200	0.440	0.412	18.870	1.76E-04	1.803	9.017

Note: In NUREG-1903 (and the above table), the probability of occurrence is P(x) and $P(x) = Scale \cdot \alpha \cdot \beta^{-\alpha} x^{\alpha-1} e^{-(x/\beta)^{\alpha}}$ where x is the PGA amplitude in centimeters per square second (cm/s²).

Table A-2. Scale factors, Original Design SSE PGA Values, Weibull Fit Coefficients to Mean PGA Probability Curves, and Calculated PGA Values at 10⁻⁶/yr Seismic Event (continued)

Site identification code	Original design SSE, g	Weibull fit parameters for mean PGA probability curves			SSE probability	PGA at 10 ⁻⁶ , g	Ratio of PGA to original SSE value 10 ⁻⁶ /ISSE
		scale	alpha	beta			
AR	0.180	0.440	0.461	15.880	1.68E-04	1.158	6.434
AS	0.180	0.460	0.464	16.300	1.78E-04	1.172	6.512
AT	0.120	0.467	0.340	6.694	2.53E-04	1.650	13.754
AU	0.200	0.472	0.369	8.041	1.12E-04	1.435	7.175
AV	0.200	0.478	0.369	8.086	1.14E-04	1.446	7.231
AW	0.100	0.520	0.435	11.150	4.53E-04	1.105	11.051
AX	0.153	0.530	0.416	7.490	1.58E-04	0.961	6.280
AY	0.153	0.546	0.342	2.249	7.78E-05	0.815	5.325
AZ	0.200	0.564	0.378	4.609	7.24E-05	0.950	4.752
BA	0.150	0.589	0.406	7.511	1.92E-04	1.072	7.149
BB	0.153	0.594	0.398	6.154	1.59E-04	0.997	6.518
BC	0.153	0.612	0.288	1.422	9.82E-05	1.212	7.924
BD	0.100	0.624	0.399	8.438	4.72E-04	1.251	12.514
BE	0.200	0.631	0.392	7.301	1.21E-04	1.198	5.992
BF	0.140	0.755	0.373	5.197	2.35E-04	1.186	8.469
BG	0.255	0.772	0.470	19.000	1.70E-04	1.440	5.647
BH	0.153	0.910	0.319	1.234	8.84E-05	0.840	5.488
BI	0.153	0.923	0.319	1.223	8.84E-05	0.836	5.464
BJ	0.153	0.930	0.425	29.320	7.13E-04	2.819	18.427
BK	0.153	1.105	0.373	5.046	2.81E-04	1.289	8.423
BL	0.200	1.239	0.370	10.030	3.48E-04	2.236	11.178
BM	0.255	1.344	0.302	1.998	9.47E-05	1.645	6.450
BN	0.100	1.414	0.328	4.706	8.55E-04	2.155	21.549
BO	0.200	2.299	0.301	1.873	2.48E-04	1.906	9.528
BP	0.160	2.592	0.241	0.355	2.25E-04	1.899	11.867
BQ	0.200	4.543	0.267	0.159	5.15E-05	0.783	3.917

Note: In NUREG-1903 (and the above table), the probability of occurrence is P(x) and

$$P(x) = Scale \cdot \alpha \cdot \beta^{-\alpha} x^{\alpha-1} e^{-(x/\beta)^{\alpha}} \text{ where } x \text{ is the PGA amplitude in centimeters per square second (cm/s}^2\text{).}$$

Table A-3a. PWR Coolant Piping Information and Calculated Values by Plant—Pipe Sizes, Material Properties, and Z-Factors

Plant identification code	Pipe leg	Inside diameter, inch	Pipe thickness, inch	Materials	ASME Code Z-factor			Best estimate Z-factor	
					Flaw location	ASME Z-factor equation	Z-factor	Flaw location	Z-factor
i	Hot leg	29.20	2.370	SS SAW	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.638	New SS SAW	1.647
ii	Crossover	30.26	2.560	SS SAW	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.641	New SS SAW	1.645
iii	Hot leg	29.00	2.450	SA351 CF8A	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.625	New SS SAW	1.644
iii	Cold leg	27.50	2.320	SA 376 304N Wrought 304 Pipe	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.606	New SS SAW	1.642
iii	Crossover leg	31.00	2.600	SA351 CF8A	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.651	New SS SAW	1.646
iv	Hot leg	29.00	2.450	SA351 CF8A	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.625	New SS SAW	1.644
iv	Cold leg	27.50	2.320	SA 376 304N Wrought 304 Pipe	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.606	New SS SAW	1.642
iv	Crossover leg	31.00	2.600	SA351 CF8A	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.651	New SS SAW	1.646
v	Hot leg	29.00	2.450	SA351 CF8A	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.625	New SS SAW	1.644
v	Cold leg	27.50	2.320	SA 376 304N Wrought 304 Pipe	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.606	New SS SAW	1.642
v	Crossover leg	31.00	2.600	SA351 CF8A	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.651	New SS SAW	1.646
vi	Hot leg	29.00	2.450	SA351 CF8A	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.625	New SS SAW	1.644
vi	Cold leg	27.50	2.320	SA 376 304N Wrought 304 Pipe	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.606	New SS SAW	1.642
vi	Crossover leg	31.00	2.600	SA351 CF8A	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.651	New SS SAW	1.646
vii	Hot leg	29.20	2.370	SA351-CF8A, stainless-steel weld	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.647
viii	Hot leg	29.20	2.310	CF8A pipe and CF8M fittings	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.649
ix	Hot leg	29.20	2.310	CF8A pipe and CF8M fittings	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.649
x	Hot leg	29.22	2.280	SA351 CF8A with SMAW and SAW welds	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.650
xi	Hot leg	29.22	2.280	SA351 CF8A with SMAW and SAW welds	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.650
xii	Hot leg	29.20	2.690	Pipe is wrought TP316 and fittings are CF8M	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.636
xii	Crossover leg	27.70	2.550	Pipe is wrought TP316 and fittings are CF8M	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.608	New SS SAW	1.635
xii	Cold leg	31.20	2.880	Pipe is wrought TP316 and fittings are CF8M	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.654	New SS SAW	1.637
xiii	Hot leg	29.20	2.310	CF8A pipe and CF8M fittings	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.649
xiv	Hot leg	29.20	2.310	CF8A pipe and CF8M fittings	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.649
xv	Hot leg	29.20	2.690	SA-351-CF8M for fittings and wrought 316 for straight pipe	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.636
xvi	Hot leg	29.20	2.370	SA-376 304N, Wrought stainless-steel pipe; SA-351-CF8A, cast stainless-steel fittings	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.647
xvii	Hot leg	29.00	2.700	SA351 CF8M	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.625	New SS SAW	1.635
xvii	Cold leg	27.50	2.560	SA351 CF8M	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.606	New SS SAW	1.633
xvii	Crossover leg	31.00	2.880	SA351 CF8M	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.651	New SS SAW	1.637
xviii	Hot leg	29.00	2.700	SA351 CF8M	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.625	New SS SAW	1.635
xviii	Cold leg	27.50	2.560	SA351 CF8M	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.606	New SS SAW	1.633
xviii	Crossover leg	31.00	2.880	SA351 CF8M	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.651	New SS SAW	1.637

Source for strength values	Material	Yield stress, psi	Ultimate stress, psi	Flow stress, psi
From ASME Code	CF8M	21,200	65,200	43,200
From ASME Code	A516Gr70	27,600	70,000	48,800
Typical actual value	CF8M	29,160	76,750	52,955
Typical actual value	A516Gr70	34,050	71,620	52,835

S _m table, ksi					
Material	@ 500 F	@ 600 F	@ 650 F	@ 550 F	@ 620 F
CF8	20.50	19.30	18.90	19.90	19.14
A516	20.50	18.70	18.40	19.60	18.58

Table A-3a. PWR Coolant Piping Information and Calculated Values by Plant in NUREG-1903—Pipe Sizes, Material Properties, and Z-Factors (continued)

Plant identification code	Pipe leg	Inside diameter, inch	Pipe thickness, inch	Materials	ASME Code Z-factor			Best estimate Z-factor	
					Flaw location	ASME Z-factor equation	Z-factor	Flaw location	Z-factor
xix	Hot leg	29.20	2.370	SA-376-TP304N, SA-351-CF8A, Cast stainless-steel fittings	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.647
xx	Hot leg	29.21	2.395	A376 TP316 for loop pipe and A351-CF8M for the elbow fittings	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.646
xx	Cold leg	27.71	2.270	A376 TP316 for loop pipe and A351-CF8M for the elbow fittings	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.608	New SS SAW	1.645
xx	Crossover leg	31.21	3.208	A376 TP316 for loop pipe and A351-CF8M for the elbow fittings	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.654	New SS SAW	1.627
xxi	Hot leg	29.21	2.395	A376 TP316 for loop pipe and A351-CF8M for the elbow fittings	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.646
xxi	Cold leg	27.71	2.270	A376 TP316 for loop pipe and A351-CF8M for the elbow fittings	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.608	New SS SAW	1.645
xxi	Crossover leg	31.21	3.208	A376 TP316 for loop pipe and A351-CF8M for the elbow fittings	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.654	New SS SAW	1.627
xxii	Hot leg	29.11	2.340	SA-351-CF8A	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.626	New SS SAW	1.648
xxii	Cold leg	27.71	2.210	SA-351-CF8A	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.608	New SS SAW	1.647
xxii	Crossover leg	31.22	2.480	SA-351-CF8A	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.654	New SS SAW	1.651
xxiii	Hot leg	29.20	2.370	SA351-CF8A, stainless-steel weld	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.628	New SS SAW	1.647
xxiv	Hot leg	42.00	3.750	A516 Gr 70	Ferritic base	$Z=1.2*(1+0.021*A*(NPS-4))$ $A=(0.125*(Rm/t)-0.25)^{0.25}$	2.010	New ferritic base	1.394
xxiv	Hot leg	42.00	3.750	Ferritic SAW	Ferritic SAW	$Z=1.35*(1+0.0184*A*(NPS-4))$ $A=(0.125*(Rm/t)-0.25)^{0.25}$	2.149	New ferritic weld	1.229
xxiv	Cold leg—suction	30.00	2.500	A516 Gr 70	Ferritic base	$Z=1.2*(1+0.021*A*(NPS-4))$ $A=(0.125*(Rm/t)-0.25)^{0.25}$	1.767	New ferritic base	1.396
xxiv	Cold leg—suction	30.00	2.500	Ferritic SAW	Ferritic SAW	$Z=1.35*(1+0.0184*A*(NPS-4))$ $A=(0.125*(Rm/t)-0.25)^{0.25}$	1.909	New ferritic weld	1.228
xxiv	Cold leg—suction	30.00	2.500	SS SAW	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.638	New SS SAW	1.419
xxiv	Cold leg—discharge	30.00	2.500	A516 Gr 70	Ferritic base	$Z=1.2*(1+0.021*A*(NPS-4))$ $A=(0.125*(Rm/t)-0.25)^{0.25}$	1.767	New ferritic base	1.396
xxiv	Cold leg—discharge	30.00	2.500	Ferritic SAW	Ferritic SAW	$Z=1.35*(1+0.0184*A*(NPS-4))$ $A=(0.125*(Rm/t)-0.25)^{0.25}$	1.909	New ferritic weld	1.228
xxiv	Cold leg—discharge	30.00	2.500	SS SAW	SS SAW	$Z=1.3*(1+0.01*(NPS-4))$	1.638	New SS SAW	1.419
xxv	Hot leg	42.00	3.750	SA-516-70	Ferritic SAW	$Z=1.35*(1+0.0184*A*(NPS-4))$ $A=(0.125*(Rm/t)-0.25)^{0.25}$	2.149	New ferritic weld	1.229
xxv	Cold leg—suction	30.00	2.500	SA-516-70	Ferritic SAW	$Z=1.35*(1+0.0184*A*(NPS-4))$ $A=(0.125*(Rm/t)-0.25)^{0.25}$	1.909	New ferritic weld	1.228
xxv	Cold leg—discharge	30.00	3.000	SA-516-70	Ferritic SAW	$Z=1.35*(1+0.0184*A*(NPS-4))$ $A=(0.125*(Rm/t)-0.25)^{0.25}$	1.875	New ferritic weld	1.211
xxvi	Hot leg	42.00	3.750	SA-516-70	Ferritic SAW	$Z=1.35*(1+0.0184*A*(NPS-4))$ $A=(0.125*(Rm/t)-0.25)^{0.25}$	2.149	New ferritic weld	1.229
xxvi	Cold leg—suction	30.00	2.500	SA-516-70	Ferritic SAW	$Z=1.35*(1+0.0184*A*(NPS-4))$ $A=(0.125*(Rm/t)-0.25)^{0.25}$	1.909	New ferritic weld	1.228
xxvi	Cold leg—discharge	30.00	2.500	SA-516-70	Ferritic SAW	$Z=1.35*(1+0.0184*A*(NPS-4))$ $A=(0.125*(Rm/t)-0.25)^{0.25}$	1.875	New ferritic weld	1.211

Source for strength values	Material	Yield stress, psi	Ultimate stress, psi	Flow stress, psi
From ASME Code	CF8M	21,200	65,200	43,200
From ASME Code	A516Gr70	27,600	70,000	48,800
Typical actual value	CF8M	29,160	76,750	52,955
Typical actual value	A516Gr70	34,050	71,620	52,835

S _m table, ksi					
Material	@ 500 F	@ 600 F	@ 650 F	@ 550 F	@ 620 F
CF8	20.50	19.30	18.90	19.90	19.14
A516	20.50	18.70	18.40	19.60	18.58

Table A-3b. PWR Coolant Piping Information and Calculated Values by Plant in NUREG-1903—Normal Operating Stresses, SSE Stresses, and 10⁻⁶ Stresses (assuming Table A-2 values are applicable) Without and With Correction Factors

Plant identification code	Pipe leg	Normal operating temperature, F	Normal operating pressure, psig	Thermal expansion stress, ksi	Normal operating stress with pressure and thermal expansion, ksi	SSE stress at worst location, ksi	N+1SSE stress, ksi	1E-6 seismic stress—linear extrapolated, ksi	N+1E-6 seismic stress—linear extrapolated, ksi	Seismic scale factor	N+1E-6 stress with seismic scale factor, ksi	N+1E-6 stress with seismic scale factor and elastic stress correction, ksi
i	Hot leg	617	2,235	0.51	9.87	15.36	25.23	102.06	111.93	0.485	59.37	34.61
ii	Crossover	547	2,200	0.52	9.56	8.36	17.92	114.95	124.51	0.230	36.00	30.39
iii	Hot leg	617	2,250	7.02	16.15	12.96	29.12	51.76	67.92	0.510	42.54	31.57
iii	Cold leg	557	2,305	0.69	10.08	21.45	31.53	85.64	95.72	0.510	53.73	33.59
iii	Crossover leg	557	2,215	0.00	8.19	9.31	17.51	37.18	45.38	0.510	27.15	27.15
iv	Hot leg	617	2,250	7.02	16.15	12.96	29.12	51.76	67.92	0.510	42.54	31.57
iv	Cold leg	557	2,305	0.69	10.08	21.45	31.53	85.64	95.72	0.510	53.73	33.59
iv	Crossover leg	557	2,215	0.00	8.19	9.31	17.51	37.18	45.38	0.510	27.15	27.15
v	Hot leg	617	2,250	7.02	16.15	12.96	29.12	56.77	72.93	0.528	46.13	32.22
v	Cold leg	557	2,305	0.69	10.08	21.45	31.53	93.93	104.01	0.528	59.68	34.66
v	Crossover leg	557	2,215	0.00	8.19	9.31	17.51	40.78	48.98	0.528	29.73	29.26
vi	Hot leg	617	2,250	7.02	16.15	12.96	29.12	56.77	72.93	0.528	46.13	32.22
vi	Cold leg	557	2,305	0.69	10.08	21.45	31.53	93.93	104.01	0.528	59.68	34.66
vi	Crossover leg	557	2,215	0.00	8.19	9.31	17.51	40.78	48.98	0.528	29.73	29.26
vii	Hot leg	617	2,235	12.21	21.57	7.31	28.87	28.62	50.19	0.588	38.38	30.82
viii	Hot leg	618	2,235	9.39	18.93	7.81	26.73	55.81	74.73	0.673	56.51	34.09
ix	Hot leg	618	2,235	9.39	18.93	7.81	26.73	55.81	74.73	0.673	56.51	34.09
x	Hot leg	611	2,235	11.93	21.56	4.36	25.93	30.21	51.77	0.718	43.25	31.70
xi	Hot leg	611	2,235	11.93	21.56	4.36	25.93	30.21	51.77	0.718	43.25	31.70
xii	Hot leg	613	2,235	12.96	21.50	4.56	26.06	35.37	56.87	0.756	48.24	32.60
xii	Crossover leg	555	2,235	0.00	7.34	8.43	15.77	65.32	72.66	0.756	56.72	34.13
xii	Cold leg	555	2,235	12.29	20.89	4.42	25.31	34.28	55.17	0.756	46.81	32.34
xiii	Hot leg	618	2,235	9.39	18.93	7.81	26.73	49.03	67.95	0.591	47.92	32.54
xiv	Hot leg	618	2,235	9.39	18.93	7.81	26.73	49.03	67.95	0.591	47.92	32.54
xv	Hot leg	599	2,235	8.52	17.13	3.13	20.27	34.27	51.40	0.828	45.50	32.11
xvi	Hot leg	617	2,235	15.37	24.72	6.54	31.27	36.96	61.68	0.472	42.17	31.50
xvii	Hot leg	613	2,235	10.98	19.46	1.44	20.89	9.36	28.82	0.979	28.62	28.62
xvii	Cold leg	555	2,290	0.00	8.23	8.35	16.58	54.38	62.61	0.979	61.47	34.98
xvii	Crossover leg	555	2,200	3.40	11.86	4.18	16.04	27.23	39.09	0.979	38.51	30.85
xviii	Hot leg	613	2,235	10.98	19.46	1.44	20.89	9.36	28.82	0.979	28.62	28.62
xviii	Cold leg	555	2,290	0.00	8.23	8.35	16.58	54.38	62.61	0.979	61.47	34.98
xviii	Crossover leg	555	2,200	3.40	11.86	4.18	16.04	27.23	39.09	0.979	38.51	30.85

Table A-3b. PWR Coolant Piping Information and Calculated Values by Plant in NUREG-1903—Normal Operating Stresses, SSE Stresses, and 10⁻⁶ Stresses (assuming Table A-2 values are applicable) Without and With Correction Factors (continued)

Plant identification code	Pipe leg	Normal operating temperature, F	Normal operating pressure, psig	Thermal expansion stress, ksi	Normal operating stress with pressure and thermal expansion, ksi	SSE stress at worst location, ksi	N+ISSE stress, ksi	1E-6 seismic stress—linear extrapolated, ksi	N+1E-6 seismic stress—linear extrapolated, ksi	Seismic scale factor	N+1E-6 stress with seismic scale factor, ksi	N+1E-6 stress with seismic scale factor and elastic stress correction, psi
xix	Hot leg	619	2,235	14.29	23.65	3.03	26.68	16.35	39.99	0.549	32.62	29.78
xx	Hot leg	608	2,250	9.65	18.99	2.58	21.57	10.67	29.66	0.764	27.15	27.15
xx	Cold leg	547	2,250	1.54	10.95	2.16	13.11	8.93	19.89	0.764	17.78	17.78
xx	Crossover leg	547	2,250	0.41	8.44	0.73	9.17	3.02	11.46	0.764	10.75	10.75
xxi	Hot leg	608	2,250	9.65	18.99	2.58	21.57	10.67	29.66	0.764	27.15	27.15
xxi	Cold leg	547	2,250	1.54	10.95	2.16	13.11	8.93	19.89	0.764	17.78	17.78
xxi	Crossover leg	547	2,250	0.41	8.44	0.73	9.17	3.02	11.46	0.764	10.75	10.75
xxii	Hot leg	618	2,250	10.31	19.78	5.87	25.65	37.75	57.53	0.563	41.03	31.30
xxii	Cold leg	558	2,305	4.27	14.06	11.73	25.80	75.49	89.55	0.563	56.55	34.10
xxii	Crossover leg	558	2,250	0.00	7.80	8.65	16.45	55.62	63.42	0.563	39.11	30.95
xxiii	Hot leg	617	2,235	12.21	21.57	7.31	28.87	41.73	63.30	0.549	44.48	31.92
xxiv	Hot leg	650	2,250	12.27	21.72	3.23	24.94	30.17	44.47	0.480	36.20	30.43
xxiv	Hot leg	650	2,250	0.00	21.72	3.23	24.94	30.17	44.47	0.480	36.20	30.43
xxiv	Cold leg—suction	550	2,250	13.00	9.63	6.88	16.50	64.33	66.08	0.480	40.51	31.21
xxiv	Cold leg—suction	550	2,250	13.00	9.63	6.88	16.50	64.33	66.08	0.480	40.51	31.21
xxiv	Cold leg—suction	550	2,250	0.35	9.63	6.88	16.50	64.33	66.08	0.480	40.51	31.21
xxiv	Cold leg—discharge	550	2,250	0.35	10.42	8.88	19.30	83.06	85.60	0.480	50.29	32.97
xxiv	Cold leg—discharge	550	2,250	0.35	10.42	8.88	19.30	83.06	85.60	0.480	50.29	32.97
xxiv	Cold leg—discharge	550	2,250	1.15	10.42	8.88	19.30	83.06	85.60	0.480	50.29	32.97
xxv	Hot leg	650	2,250	1.15	19.69	1.21	20.90	7.24	19.51	1.077	27.49	27.49
xxv	Cold leg—suction	550	2,250	1.15	10.02	4.47	14.50	26.81	28.96	1.077	38.90	30.92
xxv	Cold leg—discharge	550	2,250	10.87	8.39	7.67	16.06	45.95	47.59	1.077	57.89	34.34
xxvi	Hot leg	650	2,250	0.75	18.45	2.60	21.05	17.25	28.27	0.591	28.65	28.65
xxvi	Cold leg—suction	550	2,250	0.24	11.38	5.67	17.05	37.68	41.18	0.591	33.66	29.97
xxvi	Cold leg—discharge	550	2,250	9.63	9.53	9.30	18.83	61.79	63.44	0.591	46.07	32.21

Table A-3c. PWR Coolant Piping Information and Calculated Values by Plant—Calculated Surface-Flaw Geometries Using ASME Code Strength Assumption (assuming Table A-2 values are applicable)

Plant identification code	Pipe leg	Flaw depth a/t by ASME Code procedure (using ASME Code strengths) as a function of flaw length									
		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
	Flaw length/pipe circumference										
i	Hot leg	0.317	0.164	0.117	0.110	0.108	0.106	0.104	0.103	0.103	0.102
ii	Crossover	0.750	0.750	0.617	0.499	0.440	0.411	0.401	0.401	0.401	0.401
iii	Hot leg	0.148	0.123	0.115	0.110	0.107	0.105	0.104	0.103	0.102	0.102
iii	Cold leg	0.146	0.123	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
iii	Crossover leg	0.750	0.750	0.628	0.508	0.447	0.417	0.407	0.406	0.406	0.406
iv	Hot leg	0.148	0.123	0.115	0.110	0.107	0.105	0.104	0.103	0.102	0.102
iv	Cold leg	0.146	0.123	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
iv	Crossover leg	0.750	0.750	0.628	0.508	0.447	0.417	0.407	0.406	0.406	0.406
v	Hot leg	0.148	0.123	0.115	0.110	0.107	0.105	0.104	0.103	0.102	0.102
v	Cold leg	0.146	0.123	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
v	Crossover leg	0.750	0.750	0.628	0.508	0.447	0.417	0.407	0.406	0.406	0.406
vi	Hot leg	0.148	0.123	0.115	0.110	0.107	0.105	0.104	0.103	0.102	0.102
vi	Cold leg	0.146	0.123	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
vi	Crossover leg	0.750	0.750	0.628	0.508	0.447	0.417	0.407	0.406	0.406	0.406
vii	Hot leg	0.289	0.150	0.115	0.110	0.108	0.106	0.104	0.103	0.103	0.102
viii	Hot leg	0.562	0.292	0.207	0.169	0.151	0.145	0.144	0.144	0.144	0.144
ix	Hot leg	0.562	0.292	0.207	0.169	0.151	0.145	0.144	0.144	0.144	0.144
x	Hot leg	0.750	0.446	0.315	0.257	0.228	0.217	0.215	0.215	0.215	0.215
xi	Hot leg	0.750	0.446	0.315	0.257	0.228	0.217	0.215	0.215	0.215	0.215
xii	Hot leg	0.750	0.448	0.317	0.259	0.231	0.220	0.219	0.219	0.219	0.219
xii	Crossover leg	0.750	0.750	0.750	0.617	0.541	0.503	0.488	0.486	0.486	0.486
xii	Cold leg	0.750	0.468	0.332	0.271	0.242	0.230	0.228	0.228	0.228	0.228
xiii	Hot leg	0.562	0.292	0.207	0.169	0.151	0.145	0.144	0.144	0.144	0.144
xiv	Hot leg	0.562	0.292	0.207	0.169	0.151	0.145	0.144	0.144	0.144	0.144
xv	Hot leg	0.750	0.750	0.622	0.504	0.444	0.416	0.406	0.405	0.405	0.405
xvi	Hot leg	0.145	0.122	0.115	0.110	0.108	0.106	0.104	0.103	0.103	0.102
xvii	Hot leg	0.750	0.750	0.629	0.509	0.449	0.420	0.410	0.410	0.410	0.410
xvii	Cold leg	0.750	0.750	0.716	0.578	0.508	0.473	0.460	0.458	0.458	0.458
xvii	Crossover leg	0.750	0.750	0.750	0.632	0.554	0.515	0.499	0.496	0.496	0.496
xviii	Hot leg	0.750	0.750	0.629	0.509	0.449	0.420	0.410	0.410	0.410	0.410
xviii	Cold leg	0.750	0.750	0.716	0.578	0.508	0.473	0.460	0.458	0.458	0.458
xviii	Crossover leg	0.750	0.750	0.750	0.632	0.554	0.515	0.499	0.496	0.496	0.496

Table A-3c. PWR Coolant Piping Information and Calculated Values by Plant—Calculated Surface-Flaw Geometries Using ASME Code Strength Assumption (assuming Table A-2 values are applicable) (continued)

Plant identification code	Pipe leg	Flaw depth a/t by ASME Code procedure (using ASME Code strengths) as a function of flaw length									
		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
	Flaw length/pipe circumference										
xix	Hot leg	0.750	0.435	0.308	0.251	0.223	0.212	0.211	0.211	0.211	0.211
xx	Hot leg	0.750	0.750	0.560	0.454	0.400	0.375	0.366	0.366	0.366	0.366
xx	Cold leg	0.750	0.750	0.750	0.750	0.661	0.610	0.586	0.578	0.578	0.578
xx	Crossover leg	0.750	0.750	0.750	0.750	0.750	0.735	0.703	0.690	0.688	0.688
xxi	Hot leg	0.750	0.750	0.560	0.454	0.400	0.375	0.366	0.366	0.366	0.366
xxi	Cold leg	0.750	0.750	0.750	0.750	0.661	0.610	0.586	0.578	0.578	0.578
xxi	Crossover leg	0.750	0.750	0.750	0.750	0.750	0.735	0.703	0.690	0.688	0.688
xxii	Hot leg	0.750	0.427	0.302	0.247	0.220	0.208	0.207	0.207	0.207	0.207
xxii	Cold leg	0.522	0.271	0.192	0.157	0.140	0.134	0.134	0.134	0.134	0.134
xxii	Crossover leg	0.750	0.750	0.693	0.559	0.491	0.456	0.442	0.441	0.441	0.441
xxiii	Hot leg	0.289	0.150	0.115	0.110	0.108	0.106	0.104	0.103	0.103	0.102
xxiv	Hot leg	0.630	0.327	0.232	0.190	0.171	0.164	0.164	0.164	0.164	0.164
xxiv	Hot leg	0.125	0.125	0.125	0.125	0.125	0.088	0.076	0.072	0.068	0.066
xxiv	Cold leg—suction	0.750	0.750	0.750	0.750	0.676	0.624	0.600	0.593	0.593	0.593
xxiv	Cold leg—suction	0.750	0.750	0.750	0.728	0.636	0.589	0.567	0.562	0.562	0.562
xxiv	Cold leg—suction	0.750	0.750	0.750	0.664	0.582	0.540	0.522	0.519	0.519	0.519
xxiv	Cold leg—discharge	0.750	0.750	0.582	0.472	0.417	0.391	0.383	0.383	0.383	0.383
xxiv	Cold leg—discharge	0.750	0.685	0.484	0.393	0.348	0.328	0.324	0.324	0.324	0.324
xxiv	Cold leg—discharge	0.750	0.750	0.682	0.551	0.485	0.453	0.441	0.440	0.440	0.440
xxv	Hot leg	0.506	0.263	0.187	0.154	0.138	0.133	0.133	0.133	0.133	0.133
xxv	Cold leg—suction	0.750	0.750	0.750	0.659	0.578	0.536	0.519	0.515	0.515	0.515
xxv	Cold leg—discharge	0.750	0.750	0.750	0.735	0.644	0.597	0.576	0.571	0.571	0.571
xxvi	Hot leg	0.443	0.230	0.164	0.135	0.125	0.118	0.118	0.118	0.118	0.118
xxvi	Cold leg—suction	0.750	0.750	0.635	0.514	0.453	0.424	0.414	0.413	0.413	0.413
xxvi	Cold leg—discharge	0.750	0.750	0.713	0.576	0.507	0.472	0.459	0.458	0.458	0.458

**Table A-3d. PWR Coolant Piping Information and Calculated Values by Plant—Calculated Surface-Flaw Geometries
Using ASME Code with Typical Actual Strength Assumption (assuming Table A-2 values are applicable)**

Plant identification code	Pipe leg	Flaw depth a/t by ASME Code procedure (using typical actual strengths) as a function of flaw length									
Flaw length/pipe circumference		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
i	Hot leg	0.750	0.616	0.436	0.355	0.316	0.299	0.296	0.296	0.296	0.296
ii	Crossover	0.750	0.750	0.750	0.666	0.584	0.543	0.526	0.523	0.523	0.523
iii	Hot leg		0.464	0.329	0.269	0.241	0.230	0.229	0.229	0.229	0.229
iii	Cold leg		0.135	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
iii	Crossover leg		0.750	0.750	0.672	0.589	0.548	0.530	0.527	0.527	0.527
iv	Hot leg		0.464	0.329	0.269	0.241	0.230	0.229	0.229	0.229	0.229
iv	Cold leg		0.135	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
iv	Crossover leg		0.750	0.750	0.672	0.589	0.548	0.530	0.527	0.527	0.527
v	Hot leg		0.464	0.329	0.269	0.241	0.230	0.229	0.229	0.229	0.229
v	Cold leg		0.135	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
v	Crossover leg		0.750	0.750	0.672	0.589	0.548	0.530	0.527	0.527	0.527
vi	Hot leg		0.464	0.329	0.269	0.241	0.230	0.229	0.229	0.229	0.229
vi	Cold leg		0.135	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
vi	Crossover leg		0.750	0.750	0.672	0.589	0.548	0.530	0.527	0.527	0.527
vii	Hot leg		0.605	0.428	0.349	0.310	0.294	0.291	0.291	0.291	0.291
viii	Hot leg		0.713	0.503	0.409	0.363	0.342	0.337	0.337	0.337	0.337
ix	Hot leg		0.713	0.503	0.409	0.363	0.342	0.337	0.337	0.337	0.337
x	Hot leg		0.750	0.586	0.476	0.420	0.394	0.386	0.386	0.386	0.386
xi	Hot leg		0.750	0.586	0.476	0.420	0.394	0.386	0.386	0.386	0.386
xii	Hot leg		0.750	0.592	0.481	0.425	0.400	0.393	0.393	0.393	0.393
xii	Crossover leg		0.750	0.750	0.750	0.664	0.615	0.593	0.588	0.588	0.588
xii	Cold leg		0.750	0.603	0.490	0.433	0.407	0.400	0.400	0.400	0.400
xiii	Hot leg		0.713	0.503	0.409	0.363	0.342	0.337	0.337	0.337	0.337
xiv	Hot leg		0.713	0.503	0.409	0.363	0.342	0.337	0.337	0.337	0.337
xv	Hot leg		0.750	0.750	0.670	0.588	0.547	0.530	0.528	0.528	0.528
xvi	Hot leg		0.483	0.342	0.280	0.250	0.238	0.237	0.237	0.237	0.237
xvii	Hot leg		0.750	0.750	0.674	0.592	0.551	0.533	0.531	0.531	0.531
xvii	Cold leg		0.750	0.750	0.729	0.638	0.592	0.572	0.567	0.567	0.567
xvii	Crossover leg		0.750	0.750	0.750	0.675	0.625	0.602	0.597	0.597	0.597
xviii	Hot leg		0.750	0.750	0.674	0.592	0.551	0.533	0.531	0.531	0.531
xviii	Cold leg		0.750	0.750	0.729	0.638	0.592	0.572	0.567	0.567	0.567
xviii	Crossover leg		0.750	0.750	0.750	0.675	0.625	0.602	0.597	0.597	0.597

Table A-3d. PWR Coolant Piping Information and Calculated Values by Plant—Calculated Surface-Flaw Geometries Using ASME Code with Typical Actual Strength Assumption (assuming Table A-2 values are applicable) (continued)

Plant identification code	Pipe leg	Flaw depth a/t by ASME (using typical actual strengths) as a function of flaw length									
Flaw length/pipe circumference		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
xix	Hot leg		0.750	0.582	0.472	0.417	0.392	0.384	0.384	0.384	0.384
xx	Hot leg		0.750	0.750	0.629	0.553	0.514	0.499	0.497	0.497	0.497
xx	Cold leg		0.750	0.750	0.750	0.750	0.700	0.670	0.659	0.658	0.658
xx	Crossover leg		0.750	0.750	0.750	0.750	0.750	0.750	0.750	0.747	0.747
xxi	Hot leg		0.750	0.750	0.629	0.553	0.514	0.499	0.497	0.497	0.497
xxi	Cold leg		0.750	0.750	0.750	0.750	0.700	0.670	0.659	0.658	0.658
xxi	Crossover leg		0.750	0.750	0.750	0.750	0.750	0.750	0.750	0.747	0.747
xxii	Hot leg		0.750	0.577	0.468	0.414	0.389	0.381	0.381	0.381	0.381
xxii	Cold leg		0.695	0.491	0.399	0.354	0.334	0.329	0.329	0.329	0.329
xxii	Crossover leg		0.750	0.750	0.712	0.623	0.577	0.557	0.552	0.552	0.552
xxiii	Hot leg		0.605	0.428	0.349	0.310	0.294	0.291	0.291	0.291	0.291
xxiv	Hot leg		0.504	0.357	0.292	0.261	0.249	0.248	0.248	0.248	0.248
xxiv	Hot leg		0.125	0.125	0.125	0.125	0.088	0.076	0.072	0.068	0.066
xxiv	Cold leg—suction		0.750	0.750	0.750	0.716	0.661	0.634	0.626	0.625	0.625
xxiv	Cold leg—suction		0.750	0.750	0.750	0.680	0.628	0.604	0.598	0.598	0.598
xxiv	Cold leg—suction		0.750	0.750	0.719	0.630	0.584	0.563	0.559	0.559	0.559
xxiv	Cold leg—discharge		0.750	0.672	0.544	0.480	0.448	0.437	0.437	0.437	0.437
xxiv	Cold leg—discharge		0.750	0.583	0.473	0.418	0.393	0.385	0.385	0.385	0.385
xxiv	Cold leg—discharge		0.750	0.750	0.616	0.542	0.504	0.490	0.488	0.488	0.488
xxv	Hot leg		0.447	0.317	0.259	0.232	0.222	0.222	0.222	0.222	0.222
xxv	Cold leg—suction		0.750	0.750	0.715	0.626	0.580	0.560	0.556	0.556	0.556
xxv	Cold leg—discharge		0.750	0.750	0.750	0.687	0.636	0.613	0.607	0.607	0.607
xxvi	Hot leg		0.418	0.296	0.243	0.218	0.209	0.208	0.208	0.208	0.208
xxvi	Cold leg—suction		0.750	0.720	0.582	0.513	0.478	0.465	0.464	0.464	0.464
xxvi	Cold leg—discharge		0.750	0.750	0.639	0.561	0.522	0.506	0.504	0.504	0.504

Table A-3e. PWR Coolant Piping Information and Calculated Values by Plant—Calculated Surface-Flaw Geometries Using Best Estimate Procedure (assuming Table A-2 values are applicable)

Plant identification code	Pipe leg	Flaw depth a/t by best estimate procedure as a function of flaw length									
Flaw length/pipe circumference		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
i	Hot leg	1.000	0.614	0.434	0.354	0.315	0.298	0.295	0.295	0.295	0.295
ii	Crossover		0.855	0.603	0.489	0.433	0.406	0.398	0.398	0.398	0.398
iii	Hot leg		0.791	0.558	0.453	0.401	0.377	0.371	0.371	0.371	0.371
iii	Cold leg		0.679	0.480	0.390	0.346	0.327	0.323	0.323	0.323	0.323
iii	Crossover leg			0.726	0.587	0.517	0.482	0.469	0.468	0.468	0.468
iv	Hot leg		0.791	0.558	0.453	0.401	0.377	0.371	0.371	0.371	0.371
iv	Cold leg		0.679	0.480	0.390	0.346	0.327	0.323	0.323	0.323	0.323
iv	Crossover leg			0.726	0.587	0.517	0.482	0.469	0.468	0.468	0.468
v	Hot leg		0.754	0.533	0.433	0.384	0.361	0.356	0.356	0.356	0.356
v	Cold leg		0.617	0.436	0.355	0.316	0.299	0.296	0.296	0.296	0.296
v	Crossover leg		0.916	0.646	0.523	0.462	0.433	0.423	0.423	0.423	0.423
vi	Hot leg		0.754	0.533	0.433	0.384	0.361	0.356	0.356	0.356	0.356
vi	Cold leg		0.617	0.436	0.355	0.316	0.299	0.296	0.296	0.296	0.296
vi	Crossover leg		0.916	0.646	0.523	0.462	0.433	0.423	0.423	0.423	0.423
vii	Hot leg		0.829	0.585	0.475	0.419	0.394	0.386	0.386	0.386	0.386
viii	Hot leg		0.643	0.454	0.370	0.328	0.310	0.307	0.307	0.307	0.307
ix	Hot leg		0.643	0.454	0.370	0.328	0.310	0.307	0.307	0.307	0.307
x	Hot leg		0.778	0.549	0.445	0.394	0.370	0.364	0.364	0.364	0.364
xi	Hot leg		0.778	0.549	0.445	0.394	0.370	0.364	0.364	0.364	0.364
xii	Hot leg		0.738	0.522	0.425	0.377	0.356	0.351	0.351	0.351	0.351
xii	Crossover leg		0.652	0.461	0.376	0.335	0.317	0.314	0.314	0.314	0.314
xii	Cold leg		0.751	0.531	0.432	0.383	0.362	0.357	0.357	0.357	0.357
xiii	Hot leg		0.731	0.516	0.419	0.372	0.350	0.345	0.345	0.345	0.345
xiv	Hot leg		0.731	0.516	0.419	0.372	0.350	0.345	0.345	0.345	0.345
xv	Hot leg		0.766	0.541	0.440	0.391	0.368	0.363	0.363	0.363	0.363
xvi	Hot leg		0.791	0.558	0.453	0.401	0.377	0.370	0.370	0.370	0.370
xvii	Hot leg		0.961	0.678	0.549	0.485	0.454	0.444	0.443	0.443	0.443
xvii	Cold leg		0.604	0.428	0.349	0.311	0.295	0.293	0.293	0.293	0.293
xvii	Crossover leg		0.836	0.590	0.479	0.425	0.399	0.393	0.393	0.393	0.393
xviii	Hot leg		0.961	0.678	0.549	0.485	0.454	0.444	0.443	0.443	0.443
xviii	Cold leg		0.604	0.428	0.349	0.311	0.295	0.293	0.293	0.293	0.293
xviii	Crossover leg			0.590	0.479	0.425	0.399	0.393	0.393	0.393	0.393

Table A-3e. PWR Coolant Piping Information and Calculated Values by Plant—Calculated Surface-Flaw Geometries Using Best Estimate Procedure (assuming Table A-2 values are applicable) (continued)

Plant identification code	Pipe leg	Flaw depth a/t by best estimate procedure as a function of flaw length									
Flaw length/pipe circumference		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
xix	Hot leg		0.887	0.625	0.507	0.447	0.419	0.410	0.410	0.410	0.410
xx	Hot leg			0.725	0.586	0.516	0.481	0.468	0.467	0.467	0.467
xx	Cold leg				0.851	0.742	0.684	0.656	0.646	0.645	0.645
xx	Crossover leg					0.912	0.836	0.798	0.781	0.777	0.776
xxi	Hot leg			0.725	0.586	0.516	0.481	0.468	0.467	0.467	0.467
xxi	Cold leg				0.851	0.742	0.684	0.656	0.646	0.645	0.645
xxi	Crossover leg					0.912	0.836	0.798	0.781	0.777	0.776
xxii	Hot leg		0.802	0.566	0.459	0.406	0.382	0.375	0.375	0.375	0.375
xxii	Cold leg		0.646	0.456	0.371	0.330	0.311	0.308	0.308	0.308	0.308
xxii	Crossover leg		0.819	0.578	0.469	0.414	0.389	0.381	0.381	0.381	0.381
xxiii	Hot leg		0.768	0.542	0.440	0.390	0.367	0.361	0.361	0.361	0.361
xxiv	Hot leg		0.919	0.648	0.525	0.464	0.435	0.425	0.425	0.425	0.425
xxiv	Hot leg			0.778	0.629	0.553	0.515	0.500	0.499	0.499	0.499
xxiv	Cold leg—suction		0.886	0.624	0.506	0.447	0.419	0.410	0.410	0.410	0.410
xxiv	Cold leg—suction			0.760	0.614	0.540	0.503	0.488	0.486	0.486	0.486
xxiv	Cold leg—suction			0.605	0.491	0.434	0.407	0.398	0.398	0.398	0.398
xxiv	Cold leg—discharge		0.811	0.572	0.465	0.411	0.386	0.379	0.379	0.379	0.379
xxiv	Cold leg—discharge			0.716	0.579	0.510	0.476	0.463	0.462	0.462	0.462
xxiv	Cold leg—discharge		0.782	0.552	0.448	0.397	0.373	0.367	0.367	0.367	0.367
xxv	Hot leg			0.965	0.777	0.679	0.629	0.605	0.599	0.599	0.599
xxv	Cold leg—suction			0.767	0.620	0.544	0.507	0.492	0.490	0.490	0.490
xxv	Cold leg—discharge			0.696	0.564	0.498	0.466	0.455	0.455	0.455	0.455
xxvi	Hot leg			0.934	0.753	0.659	0.610	0.588	0.583	0.583	0.583
xxvi	Cold leg—suction			0.799	0.645	0.566	0.527	0.510	0.508	0.508	0.508
xxvi	Cold leg—discharge			0.748	0.605	0.532	0.495	0.481	0.480	0.480	0.480

APPENDIX B

EXAMPLE CALCULATION FOR HOT LEG (CRITICAL LOCATION IS THE GIRTH WELD OF AN SA312-TP304N SEAMLESS PIPE TO THE REACTOR PRESSURE VESSEL NOZZLE)

The following example conducts a deterministic, plant-specific surface flaw analysis using the scale factor approach described in section C.2.5.1.2 and assumes that the values for “Plant v” in tables A-3a through A-3e are applicable for the purposes of the analysis.

Steps in the Seismic Consideration Analysis

1. Obtain a mean annual probability of exceedance for the safe-shutdown earthquake (SSE) event. For illustration, it is assumed that an example plant has 0.2g for its SSE acceleration¹ and the associated annual frequency of exceedance at SSE of 5.35×10^{-5} has been obtained from its latest seismic hazard curve in peak ground acceleration (PGA).
2. Obtain the PGA value at the 10^{-6} per year (yr) probability of exceedance event and compute the ratio of PGA for the 10^{-6} /yr and SSE events. For the example plant considered herein, the PGA corresponding to the 10^{-6} /yr probability of exceedance event is estimated to be 0.876g and the resulting ratio of PGA for the 10^{-6} /yr to SSE events is given by $0.876\text{g}/0.2\text{g} = 4.380$.
3. Determine the highest SSE stress location (values corresponding to “Plant v” in tables A-3a and b for hot leg are used in this example calculation).
 - a. This information can be obtained from past leak-before-break submittals or other plant design information.
4. Determine the materials of interest at the critical location.
 - a. There is a shielded metal arc weld (SMAW)/submerged arc weld (SAW) joining the piping to a safe-end at the reactor pressure vessel nozzle.
 - b. The base metal of the pipe is TP304N wrought austenitic stainless steel, and there is a safe-end of TP304N stainless steel on the other side of the critical weld. The safe-end is short, and there is a dissimilar metal weld between the safe-end and the reactor pressure vessel nozzle. The dissimilar metal weld toughness is much greater than the stainless-steel weld metal toughness. The stainless-steel SAW weld toughness and the TP304N strength were used since they were lower bounding in this case.
5. Determine the pipe cross-sectional dimensions at the critical location (i.e., outside diameter and thickness).
 - a. For the hot leg of “Plant v” in table A-3a, the inside diameter of the pipe is 29 inches, and the pipe thickness is 2.45 inches.
 - b. The outside diameter is calculated to be 33.9 inches.
6. Determine normal operating conditions and stresses (values correspond to “Plant v” in

¹ “g” is the acceleration due to gravity, which is approximately 9.8 meters/second² (about 32.2 feet/second²).

table A-3b).

- a. Normal operating pressures and temperatures are 2,250 pounds per square inch gauge and 617 degrees Fahrenheit (°F), respectively.
 - b. The maximum normal operating stress (N), including the pressure stress, deadweight, and thermal expansion stress, is 16.15 kilopounds per square inch (ksi).
7. Determine strength values for materials of interest.
- a. Using material properties identified in the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (ASME Code), the following is obtained:
 - i. For SA-312 TP304N wrought stainless steel at 617°F, the material yield strength (S_y) value is 19.76 ksi (interpolated between the values of 600°F and 650°F in table Y-1, page 925, line 40, of Section II, Part D, of the ASME Code, 2023 Edition).
 - ii. For SA-312 TP304N wrought stainless steel at 617°F, the material tensile strength (S_u) value is 69.5 ksi (interpolated between the values of 600°F and 650°F in table U, page 663, line 32, of Section II, Part D, of the 2023 ASME Code).
 - iii. The flow stress (average of yield and ultimate strengths) is equal to 44.63 ksi.
 - iv. S_m at 617°F is 17.76 ksi (interpolated between the values of 600°F and 650°F in table 2A, page 358, line 24, of Section II, Part D, of the 2023 ASME Code).
 - b. Using typical average material properties (values from Fracture Mechanics Database for Nuclear Piping Materials (PIFRAC Database)²), the following is obtained:
 - i. For SA-312 TP304N wrought stainless steel at 617°F, the S_y value is 20.78 ksi.
 - ii. For SA-312 TP304N wrought stainless steel at 617°F, the S_u value is 63.47 ksi.
 - iii. The flow stress (average of yield and ultimate strengths) is equal to 42.12 ksi.
 - iv. The calculated S_m value (based on 90 percent of yield at temperature) is 18.71 ksi.
8. Determine the SSE stresses (value corresponds to “Plant v” in table A-3b).
- a. The SSE design stress in the hot-leg pipe at this location is 12.96 ksi. This is the unintensified stress for a pipe butt weld.
9. Determine the linearly scaled seismic stress for the 10^{-6} /yr seismic event.
- a. The value is the SSE stress multiplied by the ratio of PGA at 10^{-6} /yr to PGA at SSE from step 3. (This value is also listed in table A-3b for the hot leg of “Plant v.”)
 - b. This stress is $4.38 * 12.96 \text{ ksi} = 56.77 \text{ ksi}$.

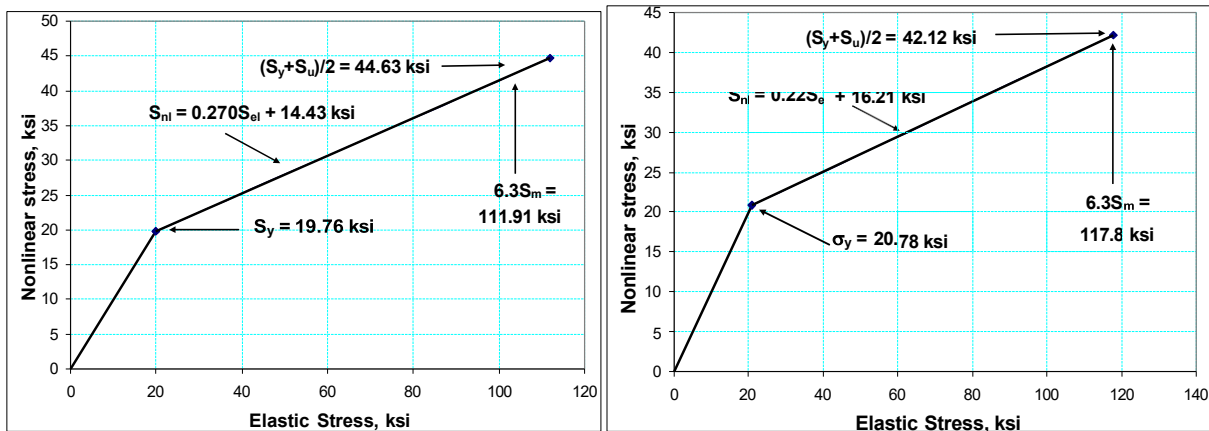
² The average values of yield and ultimate strength at 550°F can be found in NUREG/CR-6004, “Probabilistic Pipe Fracture Evaluations for Leak-Rate-Detection Applications,” issued April 1995; the value of 650°F was derived from the PIFRAC database.

10. Apply a seismic scale factor for the plant site to correct the linearly scaled stresses from step 9 and add the normal operating stresses for the 10^{-6} /yr seismic event.
 - a. The seismic scale factors for the different plant sites account for conservatisms in the original seismic design analysis to obtain a best estimate value. This value is equivalent to the reciprocal of the safety factor in the original design.
 - b. The seismic scale factor is 0.528 for this case (value corresponds to “Plant v” in table A-3b).
 - c. The correction to the linearly scaled stresses (from step 9) is $0.528 * 56.77 \text{ ksi} = 30.0 \text{ ksi}$.
 - d. The normal operating plus 10^{-6} /yr seismic stress (S_{EI}) is $30.0 + 16.15 \text{ ksi} = 46.15 \text{ ksi}$.
11. Apply a nonlinear correction factor to the elastic normal plus 10^{-6} /yr seismic stresses from step 10 to obtain the nonlinear stress (S_{NL}).
 - a. The nonlinear correction is an approximate correction to account for material plasticity in the subsequent elastic-plastic fracture mechanics (EPFM) analysis.
 - b. The correction factor was developed in NUREG-1903, “Seismic Considerations for the Transition Break Size,” issued February 2008, by assuming that the elastic stress versus nonlinear stress curve is bilinear, as illustrated in figure B-1a, when using ASME Code strength properties, or figure B-1b when using typical average properties.
 - c. If S_{EI} (from step 10) is below the yield strength, then the correction factor = 1.0 and $S_{NL} = S_{EI}$. (B2.1a)
 - d. If $S_{EI} > S_Y$ then, from figure B-1a for TP304N, S_{NL} using the ASME Code strength values is ASME Code values:

$$S_{NL} = 0.270*(S_{EI}) + 14.43 \quad (B2.1b)$$

Using typical average properties from figure B-1b for TP304N yields the following relationship:

$$S_{NL} = 0.220*(S_{EI}) + 16.2 \quad (B2.1c)$$
 - e. In this example, $S_{EI} = 46.15 \text{ ksi}$, S_{NL} (from Equation B2.1b) = 26.88 ksi for ASME Code values of strength and 26.35 ksi for typical average values of strength. These are less than 35 ksi and the NUREG-1903 methodologies, and the results are directly applicable.



(a) Using ASME Code strength and S_m values

(b) Using typical average strength and calculated S_m values

Figure B-1. Elastic-stress correction curves for TP304N using ASME Code and typical average strength values at 617°F

12. Determine the elastic-plastic correction factor (Z-factor) for the critical flaw size evaluation. In NUREG-1903, the Z-factors were derived using relationships that more accurately (and less conservatively) predict full-scale pipe test failure. In this example, the following applies:
 - a. The SAW/SMAW J-R curve is the mean minus 1 standard deviation curve with a multiplier of 1.08 to account for cyclic and dynamic loading effects on the J-R curve as given in NUREG-1903. (Seismic loading increases the toughness of a stainless-steel SAW.) A simple linear J-R curve was used with $J = 1.047 + 4.333\Delta a$ (in-lb/in.² with Δa in inches).
 - b. The Z-factor was derived for pressurized-water reactor primary piping with a radius to thickness ratio of 5 to 5.5.
 - c. The outside diameter (D) of the cold-leg pipe (value corresponds to "Plant v" in table A-3a) is 33.9 inches and was used for developing equation B2.2 rather than nominal pipe size.
 - d. The Z-factor for this SMAW pipe case is given by equation B2.2 and is 1.639. The hot-leg pipe is TP304N, but the toughness location of interest is in the SMAW weld. These Z-factors can also be obtained from figure 4-9 in NUREG-1903 for SMAW.

$$Z = 1.0922 + 0.15025D - 0.0185D^2 + 0.0011889D^3 - 0.00004102D^4 + 0.00000071875D^5 - 0.000000005014D^6 \quad (B2.2)$$

13. Determine EPFM-corrected stress (S_{EC}) for use in limit-load equations.
 - a. The EPFM-corrected stress is the nonlinear stress (from step 11) multiplied by the Z-factor (from step 12).
 - b. In this example, the $S_{EC} = 1.639 * 26.88 \text{ ksi} = 44.06 \text{ ksi}$ using the S_{NL} for the ASME Code strength properties, or $1.639 * 26.35 \text{ ksi} = 43.19 \text{ ksi}$ using the S_{NL} for the typical average

strength values.

14. Determine the minimum critical surface flaw depth from limit-load equations.

- a. ASME Code, Section XI, Appendix C, provides the limit-load equations, which are replicated in equations B2.3a–B2.3c for convenience. Note that in this calculation, the structural factor values in ASME Code, Section XI, Appendix C, are set equal to 1.0.
- b. For a long surface flaw (e.g., $\theta/\pi = 0.8$), the limit-load equations (from Article C-5321 of ASME Code, Section XI, Appendix C) are as follows:

$$\sigma_b^c = (2\sigma_f/\pi)(2-a/t)\sin(\beta) \quad (B2.3a)$$

$$\beta = (\pi/(2-a/t))(1-a/t-\sigma_m/\sigma_f) \quad (B2.3b)$$

Where:

- | | |
|--------------|---|
| σ_b^c | = critical bending stress at net section collapse (limit load) |
| σ_f | = flow stress (average of yield and ultimate strength) |
| a | = depth of surface flaw (assumed constant depth) |
| t | = pipe thickness |
| β | = fully plastic neutral axis as measured from the bottom of the pipe, radians |
| σ_m | = axial membrane stresses (frequently taken as the pressure-induced axial stress) |

- c. Equations B2.3a and B2.3b can be rearranged to give:

$$a/t = 2 - [(\pi/2)(\sigma_b^c/\sigma_f)]/\sin[\pi/(2-a/t)(1-a/t-\sigma_m/\sigma_f)] \quad (B2.3c)$$

The above equation is solved iteratively for the critical flaw depth (i.e., a/t) value.

- d. In this example,

$\sigma_m = 7.783$ ksi (from pressure stress, using $PD/4t$ with D = outside diameter in accordance with ASME Code equations)

$\sigma_f = 44.63$ ksi (using ASME Code properties from step 8.a.3) or 42.12 ksi (using typical average properties from step 8.b.4)

$\sigma_m/\sigma_f = 0.174$ (using ASME Code properties) or 0.185 (using typical average properties)

$\sigma_b^c = 44.06$ ksi (S_{EC} from step 13 for ASME Code properties) minus 7.783 ksi (σ_m from above) = 36.28 ksi, or 43.19 ksi (S_{EC} from step 13 for typical average properties) minus 7.783 ksi (σ_m from above) = 35.41 ksi

$\sigma_b^c/\sigma_f = 0.813$ (using ASME Code properties) or 0.834 (using typical average properties)

- e. Solving equation B2.3c iteratively with the above σ_b^c/σ_f and σ_m/σ_f values gives a/t values of 0.360 using ASME Code properties and 0.335 using typical average properties.

In this example, both the ASME Code and the typical average properties yield $10^{-6}/\text{yr}$ seismic a/t values that are greater than 0.25 a/t . Consequently, this example passes the transition break size requirements.