Risk-Informed Pre- and In-service Inspection Methodology for New Nuclear Deployment, Test Case Results and Regulatory Approval Protocol

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Risk-Informed Pre- and In-service Inspection Methodology for New Nuclear Deployment, Test Case Results and Regulatory Approval Protocol

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EPRI Project Manager
P. O'Regan

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ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

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The following organizations, under contract to the Electric Power Research Institute (EPRI), prepared this report:

Scientech, LLC
Curtiss-Wright Flow Control
Commercial Power & Services
1540 International Parkway
Lake Mary, FL 32746

Principal Investigator
J. Chapman

Structural Integrity Associates
5215 Hellyer Avenue
San Jose, CA 95138

Principal Investigator
S. Chesworth

EPRI
1300 West W.T. Harris Boulevard
Charlotte, NC 28262

Principal Investigator
P. O'Regan

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ABSTRACT

New nuclear power plants must comply with requirements for pre-service inspection (PSI) and in-service inspection (ISI) of pressure boundary components and supports in accordance with regulatory accepted codes and standards such as ASME Section XI. Historically, these requirements have been deterministically based; but 90% of U.S. operating plants have transitioned to risk-informed methods for identifying PSI and ISI requirements (RI-ISI), with more than 70% using EPRI-developed products. These products enable industry to focus resources on safety significant components while significantly reducing owner cost and worker exposure on non safety-significant components.

EPRI RI-ISI methodologies were reviewed against the various new plant designs to determine the viability of developing risk-informed PSI and ISI programs for them. No substantial roadblocks were identified, but some issues will need to be addressed. Key issues include use of new material with limited or no operating experience in a reactor environment, risk acceptance criteria, and the status and technical rigor of plant probabilistic risk assessment. To drive risk-informed inspection methodologies into new plant design and operation, EPRI has pursued the following strategy:

- A review of the EPRI RI-ISI methodology against Design Certification Documents (DCD) requirements has been conducted to identify any required changes or enhancements to the EPRI RI-ISI methodologies. While the methodologies themselves need not change, key inputs to the RI-ISI evaluations may not be available until the plant enters the operational phase. Updating requirements is essential in ensuring a robust PSI/ISI program.
- The RI-ISI methodology was applied to one system for each DCD.
- As the probabilistic risk assessment (PRA) is a fundamental input into developing RI-ISI programs, EPRI has developed guidance on the level of rigor needed to support a RI-ISI program for the New Build fleet while identifying when the PRA can be “completed” and needs to be “complete” (e.g., at the DCD stage, Combined Operation License Application (COLA) stage, fuel load, post operation).
- The RI-ISI methodology and its application need to be accepted by the regulator. EPRI, working with the industry, ASME and the NRC, is defining an acceptance protocol similar to that used by the existing operating fleet. The completed protocol will be communicated to the industry.

Keywords

Risk
Risk-informed in-service inspection (RI-ISI)
Probabilistic risk assessment (PRA)
Risk-informed
In-service inspection (ISI)
Probabilistic safety assessment (PSA)

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INTRODUCTION

New nuclear power plants incorporating advanced light water reactor (ALWR) technology must overcome a number of regulatory, economic, technical, and social barriers prior to licensing, construction, and successful start-up. Many of these barriers can be addressed through focused EPRI technical products and targeted deployment tools that minimize deployment risks.

The EPRI Advanced Nuclear Technology (ANT) program will complement—and help accelerate—industry activities aimed at enabling and building confidence in new nuclear plant deployment through coordinated work on cross cutting issues.

In this vein, risk-informed in-service inspection (RI-ISI) programs have been developed and implemented for a large portion of the operating fleet as alternatives to deterministic PSI and ISI programs. This report describes the results of an EPRI project to investigate the feasibility of adapting the existing RI-ISI methodologies to new plant construction and operation.

Work conducted by this project included a review of the existing RI-ISI methodology and its relevance to new plant designs; interviews conducted with Combined Operating License (COL) applicants and vendors as well as formal discussion with appropriate regulatory staff (e.g. USNRC's New Reactor Office (NRO) and Nuclear Reactor Regulation (NRR)); conducting test cases that apply the RI-ISI methodology to a number of New Build reactor coolant systems; and developing Probabilistic Risk Assessment (PRA) Technical Adequacy guidance for those portions of the PRA applicable to RI-ISI programs as well as defining the timing for when this guidance can be met and needs to be met.

2
RISK-INFORMED IN-SERVICE INSPECTION METHODOLOGY

This chapter provides a summary of the existing risk-informed inservice inspection (RI-ISI) methodologies and discusses their application to new plant construction and operation. While the term RI-ISI is used generically, the RI-ISI methodologies and ASME's codification of these methodologies (e.g. Appendix R, Code Case N716), apply to defining alternative preservice and inservice inspection requirements.

Existing Methodology Overview

EPRI Traditional RI-ISI Methodology [1]

The EPRI traditional methodology was developed for implementation on a system-by-system basis. In order to conduct and document the analysis, the piping systems are divided into segments based upon the pipe rupture potential and its consequences. The analysis is conducted on a segment basis for ease of use. It is not an integral technical component of the analyses. Differences in segment definition or segment boundary definition will have no impact on the final results for applications using the EPRI RI-ISI methodology. Each segment, which includes all the elements within the segment, is placed onto the appropriate place on the EPRI Risk Characterization Matrix as shown in Figure 2-2.

The failure potential category is determined on the basis of identified degradation mechanism.

The consequence category is based on an assessment that focuses on the impact of a pipe section failure such as loss of pressure boundary integrity on plant operation. This impact can be direct, indirect, or a combination of both:

- Direct Impacts - A failure results in a diversion of flow and a loss of the train and/or system or an initiating event such as a Loss-of-Coolant Accident (LOCA).
- Indirect Impacts - A failure results in a flood, spray, or pipe whip, spatially affecting neighboring structures, systems, and components or results in depletion of a tank and loss of the systems supplied by the tank.

The possibility of isolating a break is also identified and accounted for as part of the consequence analysis. A break could be isolated by a protective check valve, a closed isolation valve, or it could be automatically isolated by an isolation valve that closes on a given signal. If not automatically isolated, a break can be isolated by an operator action, given successful diagnosis. The likelihood of isolating a break depends on the availability of isolation equipment, a means of detecting the break, the amount of time available to prevent specific consequences (e.g., flooding of the room or draining of the tank), and human performance. If isolation is possible, the consequence assessment should be conducted for both cases: successful and unsuccessful isolation.

When conducting the consequence assessment, for each run of piping under evaluation, a spectrum of break sizes is evaluated. The break size ranges from a small leak to a rupture. Larger leaks and breaks have the potential to disable system or trains and to cause initiating events, flooding, or diversions of water sources. Typically, small breaks (minor leakage) would not render a train inoperable. They may, however, depending on the energy level of the system, spray onto adjacent equipment and cause equipment malfunction.

The consequence category is determined from the plant-specific PRA by calculating the conditional core damage probability (CCDP) and the conditional large early release probability (CLERP): High = CCDP > 1E-4; Medium = 1E-6 < CCDP < 1E-4; Low = CCDP < 1E-6. For CLERP, the boundary values are one order of magnitude smaller.

The Risk Categories shown are combined into three risk regions for more robust and efficient utilization. For risk Category 1, 2, or 3, the minimum number of inspection elements in each category should be 25 percent of the total number of elements in each risk category (rounded up to the next higher whole number). For risk Category 4 or 5, the number of inspection elements in each category should be 10 percent of the total number of elements in each risk category (rounded up to the higher whole number). Risk category 6 and 7 do not require that nondestructive examination (NDE) be performed. Pressure/leakage testing requirements remain in effect regardless of risk category (i.e. for risk categories 1 through 7).

EPRI Streamlined RI-ISI Methodology [2]

This approach is a streamlined process for implementing and maintaining RI-ISI, based upon lessons learned from numerous approved RI-ISI applications. It has been codified by ASME in Code Case N716. The N716 approach differs from the traditional RI-ISI approaches in two respects. First, the consequence assessment is not required. The consequence assessment has been replaced with a pre-determined set of high safety significant locations (e.g. reactor coolant system, break exclusion area) and a plant-specific assessment of the impact of pressure boundary failure using the plant PRA directly—any safety or non-safety related piping whose pressure boundary failure contributions to Core Damage Frequency (CDF) is greater than 1E-06 or Large, Early Release Frequency (LERF) is greater than 1E-07 based upon a plant-specific PRA is required to be within the scope of the Code Case N-716 application. The second departure is that partial scope application, which is allowed by previous RI-ISI approaches, is not allowed by N716.

According to the process, the inspection selection should equal to 10% of the high safety significant (HSS) welds, plus augmented programs for flow accelerated corrosion, localized corrosion such as Microbiologically Influenced Corrosion(MIC), and Intergranular Stress Corrosion Cracking (IGSCC) in BWRs. HSS welds are selected as follows: 1) a minimum of 25 % of the population identified as susceptible to each degradation mechanism and degradation mechanism combination; 2) for the Reactor Coolant Pressure Boundary (RCPB), at least two thirds of the examinations shall be located between the first isolation valve (i.e., isolation valve closest to the Reactor Pressure Vessel (RPV)) and the RPV; 3) a minimum of ten percent of the welds in that portion of the RCPB that lies outside containment (e.g., portions of the main feedwater system in BWRs) shall be selected, 4) a minimum of ten percent of the welds within the break exclusion region (e.g. high energy piping penetrating containment) shall be selected. Pressure/leakage testing requirements remain in effect regardless of safety significance category.

Adaptation of the RI-ISI Process to New Plant Designs

This section identifies those portions of the base risk-informed inservice inspection (RI-ISI) process that may require clarification and/or enhancement in order to support application of RI-ISI to new plant construction and operation. All other portions of the EPRI RI-ISI process remain unchanged and in effect. In this section, each step in the RI-ISI process is presented and the change (if required) is identified.

The EPRI methodology for RI-ISI is depicted in Figure 2-1. This figure reflects the basic elements of the methodology and includes refinements that were made to address specific requirements of Regulatory Guides 1.174 and 1.178 [3, 4] and lessons learned from the pilot plant studies. The EPRI RI-ISI procedure is implemented by following a six step process:

1. Definition of RI-ISI program scope
2. Failure Mode and Effects Analysis (FMEA) of Pipe Segments
   - Evaluation of consequences of pipe failures
   - Evaluation of pipe failure potential
3. Characterization of risk segments
4. Inspection element selection
5. Evaluation of risk impact of changes to inspection program
6. Implementation of the RI-ISI program

Each of these steps and relevance to implementation of the methodology by new plants is discussed in the following sections.

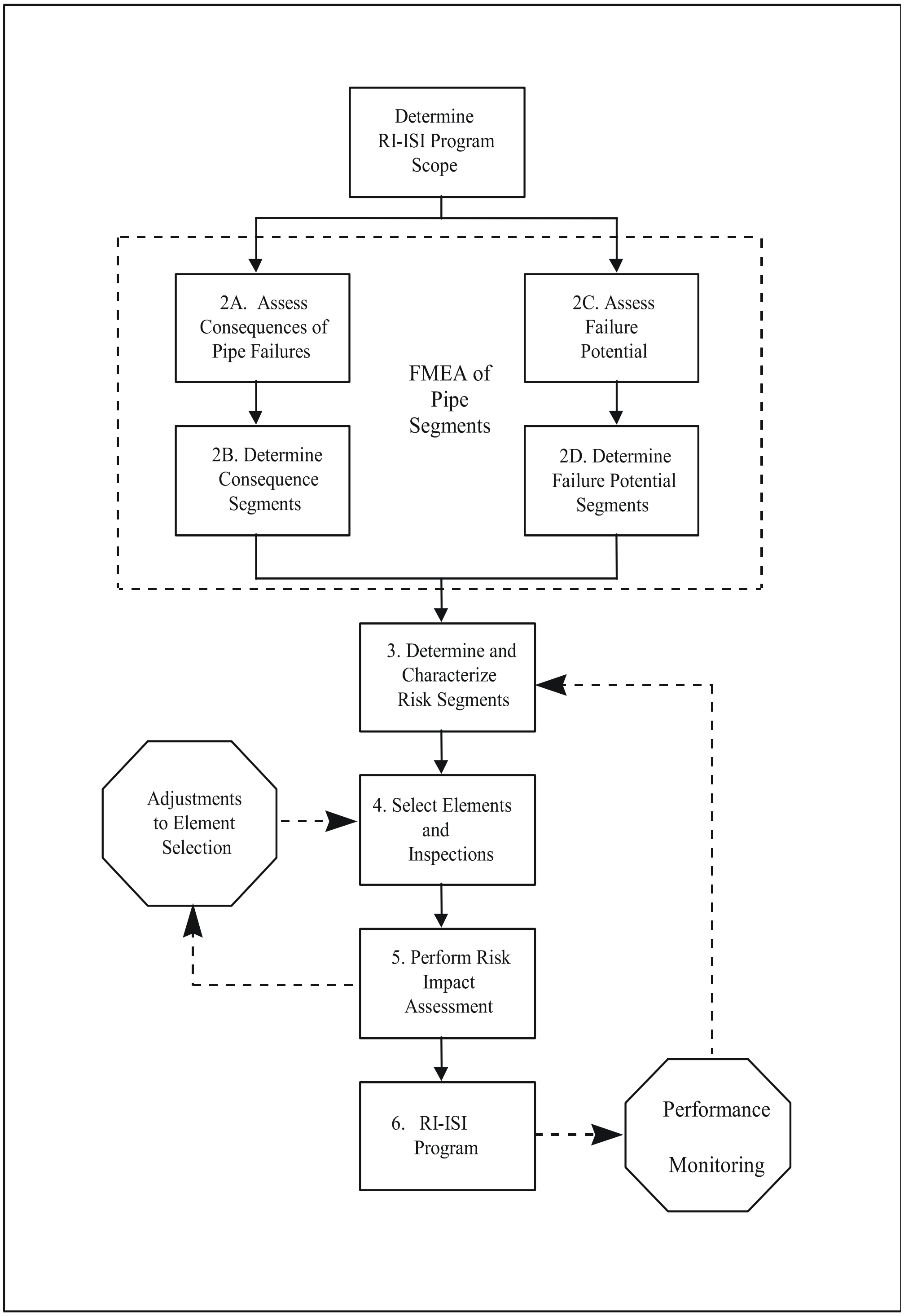

Figure 2-1
Traditional RI-ISI Methodology

1. Definition of Program Scope

Application of the traditional RI-ISI methodology to the existing fleet can be limited to a fixed scope application or can be applied to the entire plant. Options include:

- Large scope applications that include ASME Class 1, 2, and 3 and other piping systems important to safety as described in ASME Code Case N-578
- Selection of individual piping system applications or alternative piping system scope as allowed by ASME Code Case N-578
- Class 1 piping systems applications limited to Examination Category B-J welds as described in ASME Code Case N-560

Given that all DCDs and COLAs to date have referenced ASME for defining their PSI/ISI programs, there are no technical reasons why the above philosophy can not be extended to new plants. However, there may be good reasons that this decision (i.e. scope) may be agreed upon at a design centered working group level versus an individual COLA.

For the streamlined RI-ISI methodology, only a full scope application is possible. That is, Class 1, 2, 3 and non safety-related piping need to be assessed. The discussion of PRA Technical Adequacy found later is this report identifies how and why this assessment can be achieved from a RI-ISI perspective even with the plant not 100 percent built.

2.a Consequence Evaluation

The consequences of pipe rupture are measured in terms of the conditional probability of core damage given a pipe rupture (CCDP) and the conditional probability of large early release given a pipe rupture (CLERP). These measurements require quantitative risk estimates obtained from the plant specific PSA models available for the given plant. These estimates are used to calibrate tables that are applied to rank pipe rupture consequences for each location in the piping system. Once these numerical risk estimates are obtained, consequence ranking of pipe ruptures can be determined by application of these tables, without extensive PSA computations. This ranking is accomplished by identifying the impacts of the pipe rupture in terms of initiating events, system mitigation, containment response, and time of exposure of the pipe rupture conditions prior to detection and repair of the affected pipe element.

Because of the way the above process is defined, the status of design and operational documentation as well as the plant PRA will have a bearing on when the RI-ISI consequence analysis can be finalized. However, significant work can be done prior to a finalized design and certainly before construction. This is possible because the consequence assessment is addressing two types of effects, direct and indirect. Direct effects consist of the direct impact of a postulated piping failure such as loss of a pump train and can and usually are assessed in reference to Piping and Instrumentation Diagrams (P&IDs) rather than the physical plant. Indirect effects, however, are a function of plant layout and the spatial relationship between various plant components and cannot be assessed from the P&ID alone. An advantage to the design of new plants is that each is committed to meeting Standard Review Plan (SRP) 3.6.1 and 3.6.2 guidance (Design for the

Protection Against High and Moderate Energy Line Breaks) [5]. Compliance with this guidance should minimize the impact of indirect effects in comparison to some earlier plant designs in the operating fleet.

As discussed in Chapter 4, the inspections in an RI-ISI program are spread out over a ten-year inspection interval with a requirement to allocate these inspections over three inspection periods and to update the program based upon new information. As such, there is the opportunity to add, delete, or adjust inspections as the plant moves forward from initial operation into the following years of operation.

As to the EPRI streamlined RI-ISI methodology, no stand-alone consequence assessment is required. The consequence assessment is replaced with a pre-determined set of high safety significant (HSS) locations coupled with a plant-specific assessment of pressure boundary failures. A review of these pre-determined HSS locations confirmed that they are applicable to the New Build for a variety of reasons. First, even the more passive designs can have conditional consequence of failures similar to the operating fleet (e.g. CCDPs for large LOCA ranging from ~1E-2 to ~1E-03), high-energy piping routed in containment penetration areas (e.g. main feedwater, main steam), as well as the need for inspecting for defense-in-depth purposes. Additionally, the EPRI streamlined methodology requires a plant-specific assessment of all piping (safety-related and non safety-related) so that if there is anything specific to the New Build design as compared to the operating fleet experience, it will be identified as additional HSS locations.

2.b Degradation Mechanism Evaluation

In a similar fashion to the consequence assessment, failure potential of each pipe location is evaluated in terms of the relative potential for pipe rupture. The basis for correlating qualitative potential, which is determined by evaluating physical conditions needed for various degradation mechanisms, to quantitative estimates of pipe rupture frequency is a database of piping system failure rates derived from service experience. The following discussion applies equally to the traditional and streamlined RI-ISI approaches.

Reference [1] identifies those degradation mechanisms that need to be evaluated in support of a RI-ISI application including a review of plant specific service history. These mechanisms and criteria for assessing susceptibility to the mechanisms are generally suitability for application to new plant designs given the expected material and operating conditions as defined in the DCDs and COLAs. An advantage of the new plant designs is a conscious effort to use resistant material in order to preclude degradation that has been experienced in the existing operating fleet (e.g. use of chrom-moly in FAC susceptible systems).

From a failure potential perspective, except as noted in the following paragraph, the criteria used to assess failure (e.g. susceptibility to degradation) is a function of operating parameters (e.g. temperature, number of transient cycles, water chemistry control) and material as opposed to any particular plant design. For example, if a component within a BWR plant is susceptible to thermal fatigue, it is because of the magnitude of the delta T experienced, the number of cycles experienced and the specific type of material, rather than because the plant is a BWR (or an ABWR, an AP1000, an APWR, an ESBWR or an EPR). Similarly, if a component within BWR plant is susceptible to stress corrosion cracking, it is because of the magnitude of the residual stress experienced, the corrosive environment (e.g. water chemistry control) and the material (e.g. sensitized material), rather than because the plant is a BWR (or an ABWR, an AP1000, an APWR, an ESBWR or an EPR).

The one area of difference that may impact a RI-PSI/ISI program has to do with the introduction of new material not in use in the existing fleet. If there is material to be used in these new plant designs, there could be questions as the reliability of this material going forward. Based upon discussion with the ASME Working Group on the Implementation of Risk-Based Examination [6], the following additional requirements should be used in the application of the RI-ISI methodologies, both the traditional and streamlined approaches.

> *For combinations of material type and service condition with less than 10 years of operating experience, the sample shall be at least 25% of the locations (e.g. welds) containing the material*

This value of a 25% inspection population is consistent with current deterministic requirements for examination category B-J. It is anticipated that once significant, reliable operational history has been obtained for these new materials, this requirement can be re-visited and possibly less restrictive inspection requirements defined.

3. Risk Characterization

For the traditional RI-ISI methodology, piping segments with the same failure potential and consequence potential are defined as "risk segments."

Pipe elements within each segment are candidate locations to be selected for the inspection program based on the risk characterization of the segment to which each element belongs. Elements can be specific welds or locations of pipe that have been evaluated for susceptibility to a spectrum of damage mechanisms. Each segment is placed on to the appropriate place on the EPRI segment risk characterization matrix as described in Figure 2-2 based on three broad categories of failure potential (high, medium, or low) and four broad categories of consequence potential (high, medium, low, or none). Based on the combination of failure potential and consequence categories, each location on the risk matrix is assigned to one of three broad risk regions that are correlated to ranges of absolute levels of core damage frequency (CDF) and large early release frequency (LERF).

POTENTIAL FOR PIPE RUPTURE PER DEGRADATION MECHANISM SCREENING CRITERIA	**CONSEQUENCES OF PIPE RUPTURE** IMPACTS ON CONDITIONAL CORE DAMAGE PROBABILITY AND LARGE EARLY RELEASE PROBABILITY			
	NONE	**LOW**	**MEDIUM**	**HIGH**
HIGH FLOW ACCELERATED CORROSION	**LOW** **Category 7**	**MEDIUM** **Category 5**	**HIGH** **Category 3**	**HIGH** **Category 1**
MEDIUM OTHER DEGRADATION MECHANISMS	**LOW** **Category 7**	**LOW** **Category 6**	**MEDIUM** **Category 5**	**HIGH** **Category 2**
LOW NO DEGRADATION MECHANISMS	**LOW** **Category 7**	**LOW** **Category 7**	**LOW** **Category 6**	**MEDIUM** **Category 4**

Figure 2-2
Risk Matrix

For the streamlined RI-ISI approach, piping is divided into high safety significant and low safety significant scopes. HSS piping consists of the following:

- The reactor coolant pressure boundary (RCPB)
- Portions of the normal shutdown cooling pressure boundary function
- Class 2 feedwater system greater than NPS 4 (DN 100) of pressurized water reactors (PWRs) from the steam generator to the outer containment isolation valve
- Piping larger than 4 inches within the break exclusion region for high energy piping systems
- Any other piping whose contribution to core damage frequency (CDF) is greater than 1E-06 or whose contribution to large early release frequency (LERF) is greater than 1E-07

No change to the risk ranking process is expected to be required for either the traditional or streamlined RI-ISI methodologies as these processes have been developed to meet USNRC Regulatory Guide 1.174 guidance. While there is discussion underway between industry and NRC as to alternative guidance for new plants, it is believed that using either RI-ISI methodology will show very small impacts on plant risk and would therefore meet several of the alternative guidance options being discussed by industry/USNRC.

4. Element Selection

The traditional RI-ISI methodology is used to define an alternative set of inspection locations as compared to the traditional deterministic ISI program. Specific locations on the risk matrix are selected for the inspection program based on the segment's risk ranking and a set of practical considerations that bear on the feasibility and effectiveness of the specific inspection. For those locations selected for NDE inspections, the inspections are focused on the type of postulated degradation mechanism identified as part of the failure potential evaluation step. The ability to focus the examination on potential damage mechanism(s) enhances the effectiveness of the retained inspections. All locations, regardless of risk classification and element selection results, are subjected to pressure and leak testing requirements.

Because of spatial separation and increased redundancy, there may be situations where a very large number of elements are assigned to low risk categories (i.e. Risk Categories 6 or 7) to the point that new plant inspection population falls below some threshold (e.g. 10 percent for Class 1 or break exclusion region (BER) piping) that is similar to thresholds for the existing fleet and is required by the RI-ISI methodology. In such cases a basis for the low-risk ranking may need to be developed or some minimum threshold defined.

For the streamlined RI-ISI approach, the inspection selection requirement is set to a minimum of 10% of the high safety significant (HSS) welds, plus augmented programs for flow accelerated corrosion, localized corrosion (e.g. MIC) and IGSCC in BWRs. High safety significant (HSS) welds are selected as follows: 1) a minimum of 25% of the population identified as susceptible to each degradation mechanism and degradation mechanism combination shall be selected; 2) for the RCPB, at least two thirds of the examinations shall be located between the first isolation valve (i.e., isolation valve closest to the RPV) and the reactor pressure vessel; 3) a minimum of ten percent of the welds in that portion of the RCPB that lies outside containment (e.g., portions of the main feedwater system in BWRs) shall be selected; and 4) a minimum of ten percent of the welds within the break exclusion region (e.g. high energy piping penetrating containment) are to be selected.

In contrast to the traditional RI-ISI methodology, the streamlined RI-ISI methodology defines a minimum number of inspections regardless of risk significance. For example, ten percent of the reactor coolant pressure boundary shall be selected for inspection, no matter how small the risk numbers are from a PRA perspective. This rule provides an additional level of defense in depth for new plant designs.

5. Risk Impact

It must be shown that changes in risk due to changes in the number and locations of the inspections do not pose a significant adverse risk impact as determined by changes in CDF or LERF. The risk impact assessment process may involve one or more of the following: application of qualitative criteria, bounding estimates of risk impacts, realistic estimates of risk impacts, and/or adjustments to the selection of elements to meet the risk acceptance criteria.

6. Program Implementation

An integral part of implementing a RI-ISI program is the maintenance of a living RI-ISI program, including a periodic update at some time period. Updating includes reviewing the results of examinations performed as well as any indications of leakage or flaws. It also includes an evaluation of PRA changes to determine their impacts, if any, on the RI-PSI/ISI program.

3
TEST CASE RESULTS

This chapter presents the results of applying the EPRI RI-ISI methodologies to the reactor coolant system (or equivalent) for the various designs. This system was chosen for various reasons including:

- Each Design Certification Document (DCD) is pointing to ASME Section XI as the base ISI program for this system.
- There has been successful experience with this system on the operating fleet.
- Due to proximity to the reactor vessel, dose rates are expected to be higher than other systems.
- Potential for burden reduction is high.
- Inspections can only be done during outages.
- PRA insights and inputs are fairly straightforward for this system and therefore should not be significantly impacted by using the DCD PRA as opposed to the Operating License (COL) PRA.

Each of the steps in the RI-ISI methodology—consequence assessment, degradation mechanism evaluation, risk ranking and element selection, risk impact assessment—are presented in the following sections.

Consequence Assessment

There are three key components in developing the consequence assessment for RI-ISI purposes. They are initiating events, success criteria, and the plant's response to internal flooding events. Each of these is explained below.

Initiating Events – consists of equipment and component failure that perturb normal plant operation. Examples of these include turbine trips, loss of feedwater, and loss of cooling water events. From a RI-ISI perspective, the most important initiating events are those that deal with pressure boundary failures. For reactor coolant systems, loss of coolant accidents (LOCAs) are the most relevant.

Success Criteria – defines that set of equipment (e.g. components, trains, or entire systems) and operator actions needed to respond to a particular event in order to establish a stable plant condition such as long term inventory control and cooling.

Plant response to internal flooding events – while not always specifically related to reactor coolant system failures, the plant response to internal flooding events provide key insights into the overall spatial separation of the plant and associated redundancy and diversity of mitigative systems. The level of spatial separation is usually important in analyzing Class 2, 3, and non safety system failures.

The above information can be used to develop the consequence assessment (i.e. high, medium or low ranking) using the EPRI traditional RI-ISI methodology. However, if available, conditional core damage probabilities (CCDPs) and conditional large early release probabilities (CLERPs) can be used directly. CCDPs/CLERPS are the numerical equivalent of the combination of initiating event, success criteria, and plant response given a pressure boundary failure. If available, the CCDP/CLERP substantially streamlines the consequence assessment process.

For this report, a combination of CCDP/CLERP values were provided by the various vendors and/or information provided by the vendors as to initiating events, success criteria, and plant response to internal flooding events were used to conduct the consequence assessment. Additionally, as the New Build fleet is not currently in operation, generic data [7] and the EPRI look-up tables (i.e. section 3 of [1]) were utilized, as necessary.

Upon completion of the consequence assessment (i.e. identification of plant impact and remaining mitigative systems) a consequence rank is determined. The consequence rank is a function of the CCDP and CLERP values given the pressure boundary failure and is defined in the table below.

Table 3-1
Consequence Rank

Consequence Category	Corresponding CCDP Range	Corresponding CLERP Range
HIGH	CCDP > 1E-4	CLERP > 1E-5
MEDIUM	1E-6 < CCDP ≤ 1E-4	1E-7 < CLERP ≤ 1E-5
LOW	CCDP ≤ 1E-6	CLERP ≤ 1E-7

One of the advantages of the EPRI traditional RI-ISI methodology is that it is an "order of magnitude" approach to consequence ranking. For example, piping ranked at high consequence is at least two orders of magnitude more important than piping ranked at low consequence. This marked difference in ranking is of benefit because as the PRA is updated, only significant PRA changes are expected to impact the consequence ranking. This has been proved on many of the existing fleet, not only on PRA updates but also for PRAs that have been upgraded to meet the ASME PRA standard. As such, it is also expected that plants transitioning from a DCD PRA [8, 9, 10, 11, 12] to a COL PRA would not expect large changes in the consequence assessment results (i.e. the consequence ranking).

In the following table, the consequence ranking results for the reactor coolant system (RCPB) for the various New Build designs are provided. These results are further explained as follows:

LLOCA – this represents RCPB piping whose postulated failure results in a large break loss of coolant accident. This piping is located between the reactor and the first isolation valve. As such, it can not be isolated and mitigative systems (e.g. emergency core cooling) need to actuate to control inventory and provide long term cooling.

MLOCA – this represents RCPB piping whose postulated failure results in a medium break loss of coolant accident. This piping is smaller in size than a LLOCA but larger than a SLOCA. This piping is located between the reactor and the first isolation valve. As such, it can not be isolated and mitigative systems (e.g. emergency core cooling) need to actuate to control inventory and provide long term cooling.

SLOCA – this represents RCPB piping whose postulated failure results in a small break loss of coolant accident. This piping is located between the reactor and the first isolation valve. As such, it can not be isolated and mitigative systems (e.g. emergency core cooling) need to actuate to control inventory and provide long term cooling.

PLOCA – this represents RCPB piping whose postulated failure results in a loss of coolant accident if a normally closed valve fails to remain closed. This piping is located between the first and second isolation valves. If the valve fails to remain closed, isolation is lost and mitigative systems (e.g. emergency core cooling) need to actuate to control inventory and provide long term cooling. If the valve remains closed, no LOCA occurs and a stable plant condition exists.

ISLOCA – this represents RCPB piping whose postulated failure results in a loss of coolant accident but can be isolated by closing a valve. This piping is located between the first and second isolation valve. If the valve fails to close, isolation is lost and mitigative systems (e.g. emergency core cooling) need to actuate to control inventory and provide long term cooling. If the valve successfully isolates, a LOCA does not occur; but a plant transient does occur. The consequence ranking for such an event would be Low.

ILOCA-OC – this represents piping whose postulated failure results in a loss of coolant accident outside containment. This is piping located between the first isolation and second isolation valve and outside containment. If the valve fails to close, isolation is lost and reactor water is also lost outside containment. If the valve successfully isolates, a LOCA does not occur; but a plant transient does occur. The consequence ranking for such an event would be Low.

Note: while the Advanced BWR (ABWR) and Economic Simplified BWR (ESBWR) do not contain external reactor recirculation loops (RR) similar to many existing BWRs, LOCA events are still possible via failures of other systems (or portions of other systems) that makeup the reactor coolant pressure boundary (e.g. main steam, feedwater, reactor water clean-up, or shutdown cooling).

Table 3-2
ABWR Results

DESIGN	IE	Rank
ABWR	LLOCA	Medium
	MLOCA	Medium
	SLOCA	Low
	PLOCA	Low
	ILOCA	Low
	ILOCA-OC	Medium

Table 3-3
AP1000 Results

DESIGN	IE	Rank
AP1000	LLOCA	High
	MLOCA	Medium
	SLOCA	Medium
	PLOCA	Low
	ILOCA	Low
	ILOCA-OC	N/A

Table 3-4
EPR Results

DESIGN	IE	Rank
EPR (US)	LLOCA	High
	MLOCA	Medium
	SLOCA	Medium
	PLOCA	Low
	ILOCA	Low
	ILOCA-OC	N/A

Table 3-5
ESWR Results

DESIGN	IE	Rank
ESBWR	LLOCA	Medium
	MLOCA	Medium
	SLOCA	Low
	PLOCA	Low
	ILOCA	Low
	ILOCA-OC	Medium

Table 3-6
APWR Results

DESIGN	IE	Rank
APWR	LLOCA	High
	MLOCA	Medium
	SLOCA	Medium
	PLOCA	Low
	ILOCA	Low
	ILOCA-OC	N/A

Summary

The above results are similar to results seen on the existing fleet. However, while similar, they are in general somewhat lower in ranking (e.g. fewer high consequence assignments) than the existing fleet. The primary reasons for this are the increased redundancy and spatial separation of the New Build designs as compared to many units of the existing fleet.

For the streamlined RI-ISI methodology, the reactor coolant system is pre-defined as high safety significant.

Degradation Mechanism Evaluation

As discussed earlier, data regarding the new plant designs was obtained from public documents available on the NRC website [2, 3, 4, 5, 6] or vendor supplied information. Section 5.2.3 of each DCD contains information on materials, chemistry, insulation and fabrication of RCPB components. Sections 5.4, 6.3, and 9.3.4 of each DCD contain design and operating information on the RCPB (RCS and interfacing systems). The approach taken in this study was to review these Sections for each new plant design and to evaluate the susceptibility of the RCPB to the degradation mechanisms considered in the EPRI RI-ISI methodologies. The degradation mechanisms evaluated and the susceptibility criteria utilized are identical between the traditional and streamlined RI-ISI methodologies. The evaluation for each design is discussed below.

[Note: all Sections, Figures and Tables referred to in this Chapter are found in References 8. 9, 10, 11, 12]

ABWR:

Scope

Per Section 5.1, the RCPB of the ABWR includes the following systems (to the second isolation valve or outermost containment isolation valve):

- Nuclear Boiler System (NBS)
- Main Steam System (MSS), including safety/relief valve (SRV) lines
- Feedwater System (FWS)
- Reactor Recirculation System (RRS)
- Reactor Core Isolation Cooling (RCIC) System
- Residual Heat Removal (RHR) System
- Reactor Water Cleanup (CUW) System

Materials

Section 5.2.3 states that un-stabilized austenitic stainless steels used in the RCPB are primarily low carbon (L grade or nuclear grade) in order to reduce susceptibility to IGSCC. Nickel alloys include niobium stabilized Alloy 600 (Alloy 600M), and the weld metals Alloy 82 and Alloy 182 are also niobium stabilized (Alloys 82M and 182M). The selection of low carbon stainless steels represents a positive change from operating reactor designs, as does the use of niobium stabilized nickel alloys. However, the change is not substantial enough to impact the RI-ISI criteria, particularly since hydrogen water chemistry (HWC) is not mandated. Without HWC, the water will likely have significant amounts of dissolved oxygen; and components will still be susceptible to IGSCC due to crevices, cold work, welding issues, etc. In the oxidizing BWR environment, even low carbon stainless steel components can crack in the presence of crevices.

Further, until demonstrated as IGSCC resistant in the oxidizing BWR environment, niobium stabilized nickel alloy components should be considered potentially susceptible. Therefore, no changes to the current RI-ISI criteria for IGSCC are recommended.

Water Chemistry

Table 5.2-5 states that the BWR water chemistry is controlled for iron, copper, chloride, sulfate, oxygen, conductivity, and pH.

Operating Temperatures and Flow Rates

Table 1.3-1 provides the following best estimate operating temperatures, pressures, and flow rates for the RCPB at 100% power:

- Main Steam temperature (design) = 575˚F
- Main Steam flow rate = 16.843 Mlb/hr
- Feedwater temperature = 420˚F
- Feedwater flow rate = 16.807 Mlb/hr
- Recirculation pump flow rate = 30,430 gpm (per reactor internal pump (RIP))
- HPCS (High-Pressure Core Spray) flow rate = 800 gpm at 1,177 psid; 3,200 at 100 psid (2 loops)
- RCIC (Reactor Core Isolation Cooling) flow rate = 800 gpm at 165 – 1,192 psia
- Reactor shutdown cooling/LPCI(Low Pressure Coolant Injection) flow rate = 4,200 gpm at 40 psid (per pump, 3 pumps)

Assumptions

The following assumptions are applied to the evaluation of the ABWR:

- Ambient temperature inside reactor containment is assumed to be 120˚F during normal operation and 100˚F during shutdown cooling.
- Ambient temperature outside reactor containment is assumed to be 70˚F.

Degradation Mechanism Evaluation

Tables 1.3-1 and 1.3-2 provide a comparison of Nuclear Steam Supply System and Engineered Safety Features design characteristics between the ABWR design and several other designs, including the Grand Gulf BWR/6 design.

Per Table 1.3-1 and Section 5.4.1, one of the primary changes to the RCPB of the ABWR design is the presence of reactor internal pumps (RIPs) in place of the external reactor recirculation system (RRS) loops of previous BWR designs. The flow path of the SDC (Shutdown Cooling) system also differs from previous BWR designs: per Section 5.4.7.1.1.7, reactor water is cooled by pumping it directly from the reactor SDC nozzles, through the RHR heat exchangers, and back to the vessel (via feedwater on one loop and via the low pressure flooder subsystem on the other two loops).

Thermal Stratification, Cycling, and Striping (TASCS)

Scenario 1: Per Reference [9], and taking into consideration the design changes discussed above, the potential for low-flow TASCS exists in the feedwater risers of the ABWR design during plant heatup and cooldown due to mixing of FWS and cleanup (CUW) fluids in this region.

Scenario 2: As the ABWR design has no external RRS loops and no higher-pressure inleakage concerns into normally-stagnant RCPB piping, the only potential for swirl penetration TASCS would be in normally-stagnant downward-facing branch connection lines off the feedwater lines. Since system isometric drawings are not currently available, no conclusions can be drawn about the TASCS susceptibility of any such lines at this time.

Thermal Transient (TT)

Scenario 1: Per Section 6.3.1.2.1, the High Pressure Core Flooder (HPCF) system pumps water through a flooder sparger mounted above the reactor core. Coolant is supplied over the entire range of system operation pressures. The primary purpose of the HPCF system is to maintain reactor vessel inventory after small breaks that do not depressurize the reactor vessel. Per the above discussion and the conclusions reached for the similar High Pressure Core Spray (HPCS) system in Reference [9], the HPCF inlet piping near the RPV is susceptible to thermal transient (TT) during an inadvertent HPCF actuation at power.

Scenario 2: Per Section 5.4.7.1, SDC suction is taken directly from the reactor via three shutdown cooling suction nozzles on the vessel. SDC return flow is via the feedwater line on loop A and via Low Pressure Core Flooder (LPCF) subsystem discharge return lines on loops B and C. There are three RHR trains in the ABWR design versus two in a typically BWR-6 design, which provides details for a warmup procedure for the SDC suction piping. Based upon this available information, the SDC return piping near the RPV and near the loop A feedwater line is potentially susceptible to TT at the initiation of SDC operations.

Intergranular Stress Corrosion Cracking (IGSCC) – Carbon steel components are not susceptible to IGSCC, and IGSCC-resistant materials have been primarily used for other RCPB components. However, some non-carbon steel components may still be IGSCC-susceptible. EPRI RI-ISI relies upon the plant IGSCC Program to determine which components are IGSCC-resistant (Category A). All components included in the plant IGSCC Program and categorized as Category B or lower will be considered susceptible to IGSCC.

Transgranular Stress Corrosion Cracking (TGSCC) – Ruled out either due to a lack of susceptible material or a lack of initiating contaminants (per EPRI BWR Water Chemistry Guidelines).

External Stress Corrosion Cracking (ECSCC) – Ruled out either due to a lack of susceptible material or due to compliance with [13] and a lack of concentrated chloride bearing sources.

Primary Water Stress Corrosion Cracking (PWSCC) **–** Ruled out due to the fact that this mechanism only affects PWRs.

Microbiological Influenced Corrosion (MIC) **–** Ruled out due to high operating temperatures and reactor-grade water.

Pitting (PIT) **–** Ruled out due to lack of initiating contaminants, per EPRI BWR Water Chemistry Guidelines.

Crevice Corrosion (CC) **–** Per Section 5.3.3.1.4.5, the feedwater inlet nozzles, core flooder inlet nozzles, and ECCS flooding nozzles have thermal sleeves. Per Section 5.2.4.3.1, the ABWR design has eliminated creviced designs in regions where supplemental examinations were recommended by GE Service Information Letters (SIL) and Rapid Communication Service Information Letters (RICSIL). Therefore, even in locations where thermal sleeves exist, they would not be considered geometric crevices and would therefore not be susceptible to CC.

Erosion-Cavitation (E-C) **–** Ruled out due to lack of potential cavitation sources.

Flow Accelerated Corrosion (FAC) **–** EPRI RI-ISI defers to the plant FAC Program for management of this mechanism. Since it is likely that some ABWR FWS components (and possibly some other carbon steel RCPB system components with high fluid flow) will be monitored under the plant FAC Program, these locations would be considered susceptible to FAC. However, these locations are most likely far removed from the RCPB.

Therefore, TASCS, TT, and IGSCC are the only potentially active degradation mechanisms in the RCPB of the ABWR design.

AP1000:

Scope

Per Figure 5.1-5, the RCPB of the AP1000 includes the following systems:

- Reactor Coolant System (RCS) including Automatic Depressurization System (ADS) lines and pressurizer lines to the second isolation valve
- Chemical and Volume Control System (CVS) purification loop lines to the second isolation valve
- Passive Core Cooling System (PXS), including lines to the Passive Residual Heat Removal Heat Exchangers (PRHR HXs), Core Makeup Tanks (CMT), and Accumulators (ACC) to the second isolation valve
- Normal Residual Heat Removal System (RNS) lines to the second isolation valve

Materials

Section 5.2.3 states that not all wrought stainless steel in the RCPB is required to be L grade. While this is less of a concern in PWR versus BWR designs, it still means that RCPB materials are potentially susceptible to IGSCC. In addition, the Alloy 600 family of materials, including weld materials Alloy 82 and 182, have been replaced by the Alloy 690 family of materials, including weld materials Alloy 52M and 152, which are much more resistant to PWSCC.

Water Chemistry

Table 5.2-2 states that the reactor coolant water chemistry is controlled for pH, oxygen, chloride, fluoride, and other initiating contaminants.

Operating Temperatures and Flow Rates

Tables 1.3-1, 5.1-1, 5.1-2, 9.3.6-1, and 9.3.6-2, provide the following best estimate operating temperatures, pressures, and flow rates for the RCPB at 100% power:

- RCS Hot Leg temperature = 610˚F
- RCS Cold Leg / Letdown Line temperature = 537.2˚F
- RCS Pressurizer Liquid / Steam Phase temperature = 653˚F
- RCS Hot Leg pressure = 2,248 psig
- RCS Cold Leg pressure = 2, 310 psig
- RCS Pressurizer pressure = 2,235 psia
- Makeup Pump design flow rate = 140 gpm (2 pumps total)
- Letdown Line (Purification) flow rate = 100 gpm
- Charging Line (Purification) flow rate = 100 gpm

Assumptions

The following assumptions are applied to the evaluation of the AP1000:

Since no information is provided on oxygen control in the Accumulators, Core Makeup Tanks (CMTs), and In-Containment Refueling Water Storage Tank (IRWST), it shall be assumed that they are not controlled for oxygen.

Since the Boric Acid Tank (BAT) minimum operating temperature is not specified in Table 9.3.6-2 and it is located outside reactor containment, the temperature is assumed to be 70˚F.

Table 5.4-7 provides nominal pipe size (NPS) and wall thickness information for the Pressurizer surge line. Since no wall thickness data is provided for the other pipe sizes shown on Figure 5.1-

5, Schedule 120 thicknesses shall be assumed for piping NPS 4 and greater, and 160 for piping NPS 3 and smaller.

No information is provided on the Charging Line (Purification loop return) flow temperature. Since (aside from using the RCP discharge head as the motive force) the purification process is similar to that of established PWR designs, the return temperature is conservatively assumed to be 450˚F.

Ambient temperature inside reactor containment is assumed to be 120˚F during normal operation and 100˚F during shutdown cooling.

Degradation Mechanism Evaluation

TASCS

Scenario 1: Section 5.4.5.2.3 discusses pressurizer operation. Nothing in the discussion prohibits fluid insurges and outsurges between the pressurizer and the loop 1A RCS hot leg during normal operations. These insurges and outsurges can possess significant temperature differences during plant heatup and cooldown. Therefore, the horizontal portion of the pressurizer surge line is susceptible to stratified flow TASCS during plant heatup and cooldown.

Scenario 2: Section 5.4.5.2.3 states that there is a small continuous spray flow provided through a manual bypass valve around each power-operated spray valve to minimize the boron concentration difference between the pressurizer liquid and the reactor coolant. This continuous flow also prevents excessive cooling of the spray piping. Per Figure 5.1-1, the fluid source for the bypass flow is the loop 2A and 2B RCS cold legs. Near the main spray nozzle, 537.2˚F cold leg fluid encounters 653˚F Pressurizer spray, resulting in two-phase flow TASCS to any horizontal piping in this region.

Scenario 3: Stagnant branch connection lines between the main RCS loop and the first isolation valve (RNS suction line, CMT pressure balance lines, PRHR HX return line, etc.) must be evaluated under MRP-146 for TASCS susceptibility. As the MRP-146 evaluation criteria are geometry-specific, no determinations can be made regarding the TASCS susceptibility of any such lines without access to dimensioned isometric drawings.

TT

Scenario 1: None of the Passive Core Cooling System (PXS) lines may inject into the RCS unless it has been depressurized, such as during a loss of coolant accident or steam line break. Since emergency/faulted transients such as these are not evaluated under the EPRI methodology, there are no PXS injections that could result in a TT.

Scenario 2: Section 5.4.5.2.3 discusses pressurizer operation. Nothing in this section prohibits fluid insurges and outsurges between the pressurizer and the loop 1A RCS hot leg during normal operations. These insurges and outsurges can possess significant temperature differences during plant heatup and cooldown. Therefore, the pressurizer surge line is susceptible to TT during plant heatup and cooldown.

Scenario 3: Per Figure 5.1-5 (Sheet 2 of 2), the CVS pressurizer auxiliary spray line (aux spray) ties into the main spray line just upstream of the spray nozzle. Per Section 5.4.5.3.4, this flow path is used during cooldown, hot standby, and hot shutdown when the reactor coolant pumps are not operating. An inadvertent aux spray at power could result in 4" main spray piping between the aux spray tie-in and the spray nozzle (at the pressurizer steam temperature of 653˚F) being subject to 70˚F (assumed) BAT fluid at a flow rate of 140 gpm (normal single makeup pump flow), with a return of 653˚F steam following the spray transient. Based upon the criteria in the EPRI RI-ISI methodology, this scenario would result in a TT to the main spray line near the nozzle.

Scenario 4: Per Section 6.3.1.1.2, the RCS Emergency Makeup and Boration function of the PXS prevents actuation of the Automatic Depressurization System (ADS) for a significant time after a LOCA. Therefore, the ADS will only see use under emergency/faulted conditions, which are not evaluated under the EPRI methodology. Therefore, there are no transients that could result in a TT.

Scenario 5: When either CVS charging or letdown is secured for a sufficient period of time to allow portions of the line to reach ambient conditions, flow restoration will result in the mixing of fluids with significant temperature differences. In the case of the 3" letdown line, restoration will result in 537.2˚F RCS cold leg fluid entering lines at containment ambient temperature at a normal flowrate of 100 gpm (NOTE: Per Section 9.3.6.2.1.1, the CVS purification loop utilizes the developed head of the reactor coolant pumps as the motive force for the purification flow, i.e., makeup pumps are not employed during normal power operation, and the letdown and charging flow rates are identical.) In the case of the 3" charging line, flow restoration will result in a slug of ambient fluid, followed by charging fluid at 450˚F (assumed), entering 537.2˚F portions of the line near the charging nozzle at 100 gpm. Both of these scenarios would result in TTs to these lines. The portion of the charging line remote from the nozzle would only encounter the single transient of 450˚F charging fluid into ambient piping, but that would still be sufficient to result in a TT this region.

Scenario 6: Per Section 5.4.7.1.2.1, initiation of the RNS occurs four hours following reactor shutdown, after the first phase of coldown by the main steam system has reduced the RCS temperature to less than or equal to 350˚F. Section 5.4.7.4.2 discusses the RNS initiation procedure, which includes startup of the two RNS pumps and no discussion of any pre-warming procedure for the suction or discharge lines. Therefore, in the most conservative scenario, the 12" common suction line would see 350˚F RCS hot leg fluid enter ambient piping at a flow rate of 2,000 gpm (two RNS pumps), while the 8" discharge lines near the Direct Vessel Injection (DVI) nozzles would see a double-shock of ambient fluid into 350˚F lines, followed by 350˚ F fluid into ambient lines, at a flow rate of 1,000 gpm (one pump per line). While the suction line transient is not sufficient to result in a TT, the region near the RNS discharge/DVI nozzles is susceptible to a TT.

IGSCC – Oxygen control is not specified in the Accumulators, CMTs, and IRWST, and their connections to the DVI lines are also assumed to not be oxygen controlled. Depending upon the specific line geometry, there is also the potential for elevated temperatures (> 200˚F) between the first and second isolation valves in these lines. Therefore, based upon the criteria in [1], the potential for IGSCC exists in these regions.

TGSCC **–** Ruled out due to lack of initiating contaminants, per EPRI PWR Primary Water Chemistry Guidelines.

ECSCC **–** Ruled out due to compliance with [13] and lack of concentrated chloride bearing sources.

PWSCC **–** Ruled out due to the lack of Alloy 600, 82, and 182 materials.

MIC **–** Ruled out due to high operating temperatures and reactor-grade water.

PIT **–** Ruled out due to lack of initiating contaminants, per EPRI PWR Primary Water Chemistry Guidelines.

CC - Per Section 5.4.5.2.1, a thermal sleeve is present on the surge line nozzle to the pressurizer. However, EPRI PWR Primary Water Chemistry control is in effect at this location, precluding the presence of oxygen and ruling out CC as a potential degradation mechanism.

E-C **–** Ruled out due to lack of potential cavitation sources.

FAC **–** Ruled out due to the fact that all piping is stainless steel.

Therefore, TASCS, TT, and IGSCC are the only potentially active degradation mechanisms in the RCPB of the AP1000 design.

EPR (US):

Scope

Per Figure 5.1-4, the RCPB of the U.S. Evolutionary Pressurized Water Reactor (EPR) includes the following systems:

Reactor Coolant System (JAA, JEA, JEB, JEC, and JEF) including pressurizer piping to the second isolation valve

Safety Injection System and Residual Heat Removal System (JN) to the second isolation valve, including piping from Medium Head Safety Injection (MHSI), Low Head Safety Injection / Residual Heat Removal (LHSI/RHR), the Accumulators (ACCU), and the Extra Borating System (EBS)

Volume Control System (KBA) to second isolation valve

(NOTE: The Nuclear Sampling System (KUA) is also shown on this Figure; however this system will not be evaluated as all lines are less than NPS 1-1/2.”)

Materials

Section 5.2.3 states that the RCPB uses only L grade non-stabilized austenitic stainless steel piping, which is resistant to IGSCC. In addition, the Alloy 600 family of materials, including weld materials Alloy 82 and 182, have been replaced by the Alloy 690 family of materials, including weld materials Alloy 52M and 152, which are much more resistant to PWSCC.

Water Chemistry

Table 5.2-3 states that the reactor coolant water chemistry is controlled for Lithium, Hydrogen, Dissolved Oxygen, Chloride, Fluoride, Sulfate, Total Boron, and Boron 10.

Operating Temperatures and Flow Rates

Table 1.3-1, Figure 5.1-1, Table 6.3-1, Table 6.3-2, Table 6.3-4, Table 6.8-1, and Table 9.3.4-1 provide the following best estimate operating temperatures, pressures, and flow rates for the RCPB at 100% power:

- RCS Hot Leg temperature = 624.6˚F
- RCS Cold Leg / Cross-over Leg / Letdown Line temperature = 563.4˚F
- RCS Pressurizer Liquid / Steam Phase temperature = 652.7˚F
- RCS Hot Leg pressure = 2,265 psia
- RCS Cold Leg pressure = 2, 324 psia
- RCS Cross-over Leg pressure = 2, 218 psia
- RCS Pressurizer pressure = 2,500 psia
- Accumulator Tanks (minimum operating temperature) = 59.0˚F
- IRWST Tank (minimum operating temperature) = 59.0˚F
- LHSI Pump flow rate = 2,200 gpm (4 pumps total)
- MHSI Pump flow rate = 600 gpm (4 pumps total)
- EBS Pump flow rate = 52 gpm (2 pumps total)
- Volume Control Tank (VCT) temperature = 122˚F
- Charging Pump flow rate = 176 gpm (2 pumps total)
- Letdown Line flow rate = 160 gpm
- Regenerative Heat Exchanger Outlet (Charging Line) temperature = 487˚F
- Charging Line minimum flow rate = 20 gpm per line (2 lines total)

Assumptions

The following assumptions are applied to the evaluation of the U. S. EPR:

Since Tables 6.3-1, 6.3-4, and 6.8-1 provide no information on oxygen control, it shall be assumed that the Accumulator Tanks, IRWST, and EBS Tanks are not controlled for oxygen. (NOTE: Section 5.2.3.2.1 states that RCPB chemistry parameters are based on the EPRI PWR Primary Water Chemistry Guidelines.)

Since the EBS Tank minimum operating temperature is not specified in Table 6.8-1, the temperature is assumed to be identical to the Accumulator and IRWST Tank temperatures (59.0˚F).

Table 5.4-4 provides NPS and wall thickness information for the Pressurizer surge and spray lines. Since no wall thickness data is provided for the other pipe sizes shown on Figure 5.1-4, Schedule 120 thicknesses shall be assumed where not explicitly provided.

Degradation Mechanism Evaluation

TASCS

Scenario 1: Section 5.4.10.2.3 discusses Pressurizer operation. Nothing in the discussion prohibits fluid insurges and outsurges between the Pressurizer and the loop 3 RCS hot leg during normal operations. These insurges and outsurges can possess significant temperature differences during plant heatup and cooldown. Therefore, the horizontal portion of the Pressurizer surge line is susceptible to stratified flow TASCS during plant heatup and cooldown.

Scenario 2: Table 5.4-5 states that there is a continuous Pressurizer spray flow of 0.77 lbm/s per normal spray line. Section 5.4.10.2.3 states that this continuous bypass flow around the normal spray valves prevents spray line thermal shock and maintains boron equilibrium between the Pressurizer and the RCS loops. Per Figure 5.1-4, the fluid source for the bypass flow is the loop 2 and 3 RCS cold legs. Near the two dedicated main spray nozzles, 563˚F cold leg fluid encounters 653˚F Pressurizer spray, resulting in two-phase flow TASCS to any horizontal piping in this region.

Scenario 3: Stagnant branch connection lines between the main RCS loop and the first isolation valve (safety injection lines, residual heat removal lines, etc.) must be evaluated under MRP-146 for TASCS susceptibility. As the MRP-146 evaluation criteria are geometry-specific, no determinations can be made regarding the TASCS susceptibility of any such lines without access to dimensioned isometric drawings.

TT

Scenario 1: Per Section 6.8-1, the EBS is designed to inject concentrated boron solution into the RCS against any credible RCS pressure (NOTE: The MHSI, LHSI, and Accumulator Tanks cannot inject against normal RCS pressure per Tables 6.3-1, 6.3-2, and 6.3-3.). An inadvertent EBS actuation could result in 10” RCPB piping between the second isolation valve and the main

RCS loop being subject to 140˚F EBS Tank fluid at a flow rate of 26 gpm per safety injection line. Based upon the criteria in the EPRI RI-ISI methodology, this scenario does not result in a TT.

Scenario 2: Section 5.4.10.2.3 discusses Pressurizer operation. Nothing in this section prohibits fluid insurges and outsurges between the Pressurizer and the loop 3 RCS hot leg during normal operations. These insurges and outsurges can possess significant temperature differences during plant heatup and cooldown. Therefore, the Pressurizer surge line is susceptible to TT during plant heatup and cooldown.

Scenario 3: Per Figure 5.1-4, the Pressurizer auxiliary spray line (aux spray) has its own dedicated spray nozzle (i.e., does not tie into the main spray lines). Per Section 5.4.10.2.1, aux spray is provided by the chemical volume and control system (CVCS) when both main sprays are not operational and possesses a spray lance that acts as a thermal sleeve to protect the nozzle from excessive thermal loads. Per Sections 9.3.4.1 and 9.3.4.2.3.1, aux spray also operates when a decrease in RCS pressure is required during cooldown operations, as well as during the RCS pressure increase during plant heatup. An inadvertent aux spray at power could result in 4" aux spray piping near the nozzle (at the Pressurizer steam temperature of 653˚F) being subject to 122˚F Volume Control Tank fluid at a flow rate of 176 gpm (normal single pump flow), with a return of 653˚F steam following the spray transient. Based upon the criteria in the EPRI RI-ISI methodology, this scenario would result in a TT to the aux spray line near the nozzle (except possibly where the spray lance is credited for mitigation).

Scenario 4: Depending on whether the first valves off the Pressurizer are open or closed and depending upon the line geometry (whether a loop seal is present and the amount of horizontal distance involved), the portion of the pressure-operated relief valve (PORV) lines between the two isolation valves can experience a TT during a PORV actuation at power, when lines initially at containment ambient temperature encounter Pressurizer steam at 653˚F. No determinations of TT susceptibility can be made without access to dimensioned isometric drawings of these lines.

Scenario 5: When either charging or letdown is secured for a sufficient period of time to allow portions of the line to reach ambient conditions, flow restoration will result in the mixing of fluids with significant temperature differences. In the case of the 4" letdown line, restoration will result in 563˚F RCS cross-over leg fluid entering lines at containment ambient temperature at a normal flowrate of 160 gpm. In the case of the 4" charging lines, flow restoration will result in a slug of ambient fluid, followed by charging fluid at 487˚F, entering 563˚F portions of the line near the charging nozzles at 20 gpm minimum (per line). Both of these scenarios would result in TTs to these lines. The portions of the charging lines remote from the nozzles would only encounter the single transient of 487˚F charging fluid into ambient lines, which would not result in TTs to these regions.

Scenario 6: Per Section 5.4.7.2, during RCS cooldown, two trains of the RHRS are normally placed in service at an RCS temperature of 250˚F, with the remaining two trains not engaged until the RCS temperature has dropped to 212˚F. Per the criteria of Attachment 1, the initial temperature difference between the RCS and ambient RHRS piping is insufficient to result in a TT to either RHRS train regardless of the flow rate at initiation.

IGSCC **–** Per Section 6.8.1, the EBS is designed to inject concentrated boron solution into the RCS against any credible RCS pressure. An inadvertent EBS actuation could result in RCPB piping between the first and second isolation valves being filled with fluid from the EBS Tanks, which are not controlled for oxygen (NOTE: The Accumulator and IRWST Tanks are also not controlled for oxygen; however, these the systems taking suction from these tanks cannot inadvertently inject at normal RCS pressure per Tables 6.3-1, 6.3-2, and 6.3-3.). Depending upon the specific line geometry, there is also the potential for elevated temperatures (> 200˚F) between the first and second isolation valves. Therefore, based upon the criteria in [1], the potential for IGSCC exists in this portion of the safety injection lines.

TGSCC **–** Ruled out due to lack of initiating contaminants, per EPRI PWR Primary Water Chemistry Guidelines.

ECSCC **–** Ruled out due to compliance with [13] and lack of concentrated chloride bearing sources.

PWSCC **–** Ruled out due to the lack of Alloy 600, 82, and 182 materials.

MIC **–** Ruled out due to high operating temperatures and reactor-grade water.

PIT **–** Ruled out due to lack of initiating contaminants, per EPRI PWR Primary Water Chemistry Guidelines.

CC **–** Per Sections 5.4.3.2 and 5.4.10.2.1, thermal sleeves are present on the two charging nozzles to the loop 2 and 4 RCS cold legs and the surge line nozzle to the pressurizer. Also, spray lances, acting as thermal sleeves, are present on the two main spray nozzles and the auxiliary spray nozzle to the pressurizer. However, EPRI PWR Primary Water Chemistry control is in effect at all of these locations, precluding the presence of oxygen and ruling out CC as a potential degradation mechanism.

E-C **–** Ruled out due to lack of potential cavitation sources.

FAC **–** Ruled out due to the fact that all piping is stainless steel.

Therefore, TASCS, TT, and IGSCC are the only potentially active degradation mechanisms in the RCPB of the U.S. EPR design.

APWR:

The APWR design was compared to the two preceding PWR designs because a limited amount of information was provided. Based upon this review, the APWR is similar to the above with respect to design, material, and operating conditions. While there are some differences between the APWR and the PWRs evaluated above, these differences are not large and are not expected to substantially impact the degradation mechanism evaluation and conclusions as presented below.

Scope

The RCPB of the APWR includes the following systems:

Reactor Coolant System including pressurizer piping to the second isolation valve, Safety Injection System, Residual Heat Removal System, and Volume Control System

Materials

The RCPB uses only L grade non-stabilized austenitic stainless steel piping, which is resistant to IGSCC. In addition, the Alloy 600 family of materials, including weld materials Alloy 82 and 182, have been replaced by the Alloy 690 family of materials, which are much more resistant to PWSCC.

Water Chemistry

Reactor coolant water chemistry is controlled consistent with the EPRI water chemistry guidelines.

Operating Temperatures and Flow Rates

Expected to be consistent with the two PWRs previously evaluated.:

Degradation Mechanism Evaluation

TASCS

<u>Scenario 1</u>: Similar to the other two PWRs, fluid insurges and outsurges between the Pressurizer and a RCS hot leg during normal operations are possible. These insurges and outsurges can possess significant temperature differences during plant heatup and cooldown. Therefore, the horizontal portion of the Pressurizer surge line is susceptible to stratified flow TASCS during plant heatup and cooldown.

<u>Scenario 2</u>: It is also anticipated that a potential also exist resulting in two-phase flow TASCS to any horizontal piping in the normal/bypass spray region.

<u>Scenario 3</u>: Stagnant branch connection lines between the main RCS loop and the first isolation valve (safety injection lines, residual heat removal lines, etc.) must be evaluated under MRP-146 for TASCS susceptibility. As the MRP-146 evaluation criteria are geometry-specific, no determinations can be made regarding the TASCS susceptibility of any such lines without access to dimensioned isometric drawings.

TT

<u>Scenario 1</u>: A safety injection (SI) actuation could result in RCPB piping being subject to cold fluid injection onto relatively hotter piping. However, based upon the assessment of the other two PWRs, this scenario does not result in a TT.

<u>Scenario 2</u>: Similar to the other two PWRs, fluid insurges and outsurges between the Pressurizer and a RCS hot leg during normal operations are considered possible. These insurges and outsurges can possess significant temperature differences during plant heatup and cooldown. Therefore, the Pressurizer surge line is susceptible to TT during plant heatup and cooldown.

IGSCC –Depending upon the specific line geometry, there is the potential for elevated temperatures (> 200˚F) between the first and second isolation valves. Therefore, based upon the criteria in [1], the potential for IGSCC exists in this portion of the safety injection lines.

TGSCC – Ruled out due to lack of initiating contaminants, per EPRI PWR Primary Water Chemistry Guidelines.

ECSCC – Ruled out due to compliance with [13] and lack of concentrated chloride bearing sources.

PWSCC – Ruled out due to the lack of Alloy 600, 82 and 182 materials.

MIC – Ruled out due to high operating temperatures and reactor-grade water.

PIT – Ruled out due to lack of initiating contaminants, per EPRI PWR Primary Water Chemistry Guidelines.

CC – EPRI PWR Primary Water Chemistry control is in effect at all of these locations, precluding the presence of oxygen and ruling out CC as a potential degradation mechanism.

E-C – Ruled out due to lack of potential cavitation sources.

FAC – Ruled out due to the fact that all piping is stainless steel.

Therefore, TASCS, TT, and IGSCC are the only potentially active degradation mechanisms in the RCPB of the APWR design.

ESBWR:

Scope

Per Section 5.1 (particularly Section 5.1.2), the RCPB of the ESBWR includes the following systems (to the second isolation valve or outermost containment isolation valve):

Nuclear Boiler System (NBS), including Main Steam System (MSS) and Feedwater System (FWS), as well as the Automatic Depressurization System (ADS) and Safety Relief Valves (SRVs)

Isolation Condenser System (ICS)

Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) System, including the Control Rod Drive (CRD) System

Materials

Section 5.2.3 states that un-stabilized austenitic stainless steels used in the RCPB are primarily low carbon (L grade or nuclear grade) in order to reduce susceptibility to IGSCC. Nickel alloys include niobium stabilized Alloy 600 (Alloy 600M) and the weld metals Alloy 82 and Alloy 182 are also niobium stabilized (Alloys 82M and 182M). The selection of low carbon stainless steels represents a positive change from operating reactor designs, as does the use of niobium stabilized nickel alloys. However, the change is not substantial enough to impact the RI-ISI criteria, particularly since hydrogen water chemistry (HWC) is not mandated. Without HWC, the water will likely have significant amounts of dissolved oxygen; and components will still be susceptible to IGSCC (due to crevices, cold work, welding issues, etc.). In the oxidizing BWR environment, even low carbon stainless steel components can crack in the presence of crevices. Further, until demonstrated as IGSCC resistant in the oxidizing BWR environment, niobium stabilized nickel alloy components should be considered potentially susceptible. Therefore, no changes to the current RI-ISI criteria for IGSCC are recommended.

Water Chemistry

Table 5.2-5 states that the BWR water chemistry is controlled for iron, copper, chloride, sulfate, oxygen, conductivity, and pH.

Operating Temperatures and Flow Rates

Table 1.3-1 provides the following best estimate operating temperatures, pressures, and flow rates for the RCPB at 100% power:

- Main Steam temperature (design) = 575˚F
- Main Steam flow rate = 19.307 Mlb/hr
- Feedwater temperature = 420˚F
- Feedwater flow rate = 19.260 Mlb/hr

Assumptions

The following assumptions are applied to the evaluation of the ESBWR:

Ambient temperature inside reactor containment is assumed to be 120˚F during normal operation and 100˚F during shutdown cooling. Ambient temperature outside reactor containment is assumed to be 70˚F.

Degradation Mechanism Evaluation

TASCS

<u>Scenario 1</u>: As the ESBWR design has no pump-driven reactor recirculation system, no normally-stagnant branch connection lines off the feedwater lines, and no higher-pressure inleakage concerns into normally-stagnant RCPB piping, there is no potential for swirl-penetration TASCS in these lines.

<u>Scenario 2</u>: Per Section 5.4.8.1.2, during normal plant operation the RWCU/SDC system continuously recirculates water by taking suction from the mid-vessel area of the RPV and from the reactor bottom head and returning via the feedwater line to the RPV. Per Figure 1.1-3b, the temperature of the RWCU return flow is nearly identical to that of the feedwater flow; therefore, there is no potential for TASCS due to fluid mixing and stratification during normal operation.

<u>Scenario 3</u>: During plant heatup, feedwater is introduced in the reactor to raise its temperature, while cold water is “overboarded” (dumped) to the main condenser by the RWCU/SDC system. Since the RWCU return is directed to the main condenser, as opposed to the feedwater line, there is no potential for TASCS due to feedwater/RWCU fluid mixing and stratification during heatup.

<u>Scenario 4</u>: Table 5.4-1 (ICS Loop Seal) states that the ICS condensate valves feature a loop seal design to ensure that they don’t have 545˚F water on one side of the disk and subcooled (50˚F) water on the other side during normal plant operation, thus affecting leakage during system standby conditions. This arrangement means that there is no cyclic valve inleakage TASCS concern in these lines.

TT

<u>Scenario 1</u>: Per Section 5.4.8.1.2, during normal plant operation the RWCU/SDC system continuously recirculates water by taking suction from the mid-vessel area of the RPV and from the reactor bottom head and returning via the feedwater line to the RPV. Per Figure 1.1-3b, the temperature of the RWCU return flow is nearly identical to that of the feedwater flow; therefore, there is no potential for thermal transients at the mixing tee during normal operation. (NOTE: Per Section 5.4.8.1.2, at the point of introduction of the RWCU/SDC piping to the feedwater lines, the return line of the RWCU/SDC has a thermal sleeve to accommodate the maximum temperature difference that can occur between the two fluid streams under any mode of plant operation without excessive thermal stresses.)

Scenario 2: When RWCU/SDC flow is secured for a sufficient period of time to allow portions of the lines to reach ambient conditions, flow restoration will result in the mixing of fluids with significant temperature differences. In the case of the RWCU/SDC suction lines, restoration will result in 520˚F RPV fluid entering lines at containment ambient temperature at a normal flowrate of 510.7 gpm (NOTE: This value is the single-train pump flowrate; the exact breakdown of how much suction flow is in the mid-vessel suction line and how much is in the bottom-head suction line is unclear.) In the case of the RWCU/SDC return line, flow restoration will result in a slug of ambient fluid, followed by RWCU/SDC fluid at 422˚F, entering 420˚F portions of the line near the feedwater mixing tee at a normal flowrate of 510.7 gpm. The portion of the RWCU/SDC return line remote from the mixing tee would only encounter the single transient of 422˚F fluid into ambient piping. Per Section 5.4.8.1.2, the RWCU/SDC system uses large-bore piping for lines sharing an SDC function (i.e., the mid-vessel suction line and return line). The size of the reactor bottom head suction line is unknown, but would be relatively small if similar to existing BWR designs. Also per Section 5.4.8.1.2, the bottom head suction line is stainless steel, while the mid-vessel suction and return lines are carbon steel. Due to the lack of detailed pipe size information and the uncertainty in the suction flowrates, it is not possible to make a conclusion regarding TT susceptibility at this time; however, until an evaluation can be performed, the RWCU/SDC suction and return lines should be considered potentially susceptible to TT. (NOTE: Per Section 5.4.8.1.2, at the point of introduction of the RWCU/SDC piping to the feedwater lines, the return line of the RWCU/SDC has a thermal sleeve to accommodate the maximum temperature difference that can occur between the two fluid streams under any mode of plant operation without excessive thermal stresses.)

Scenario 3: Per Section 5.4.8.2.2, initiation of normal SDC via the RWCU/SDC system occurs at normal (high) plant pressure. During normal shutdown operations, plant cooldown via the RWCU/SDC system is controlled automatically. As cooldown proceeds and reactor temperatures are reduced, pump speeds are increased and various bypass valves are opened. During the early phase of shutdown, the RWCU/SDC pumps operate at reduced speed to control the cooldown rate to less than the maximum allowed RPV cooling rate. In order to maintain less than the maximum allowed RPV cooling rate, both RWCU/SDC trains are placed into operation early during the cooldown, but with the pumps and system configuration aligned to provide a moderate system flow rate, which is gradually increased as RPV temperature drops. Due to the lack of detailed pipe size and flow rate information at the time of SDC initiation, it is not possible to reach a conclusion regarding TT susceptibility in the suction or discharge lines. However, until an evaluation can be performed, these lines should be considered potentially susceptible to TT.

Scenario 4: The ICS steam supply line connection between the RPV and the isolation condenser is normally open and the condensate return line is normally closed. This arrangement allows the isolation condenser and drain piping to fill with condensate, which is maintained at a subcooled temperature by the IC/PCCS pool water during normal reactor operation. The isolation condenser is started into operation by opening condensate return valves and draining the condensate to the reactor, thus causing steam from the reactor to fill the tubes, which transfer heat to the cooler pool water. An inadvertent actuation of the ICS at power would result in subcooled condensate at 50˚F (Table 5.4-1, ICS Loop Seal) entering 520˚F lines near the reactor vessel IC return nozzle. Due to the lack of detailed flow rate information, it is not possible to reach a conclusion regarding TT susceptibility at this time; however, until an evaluation can be performed, the ICS condensate return lines should be considered potentially susceptible to TT.

<u>Scenario 5</u>: Per Section 6.3, the Gravity Drain Cooling System (GDCS) and the Standby Liquid Control System (SLCS) are initiated via the use of squib valves that cannot be closed after initiation. Therefore the GDCS/SLCS cannot be actuated inadvertently while at power, and their injection lines do not present a TT concern.

IGSCC – Carbon steel components are not susceptible to IGSCC, and IGSCC-resistant materials have been primarily used for other RCPB components. However, some non-carbon steel components may still be IGSCC-susceptible. EPRI RI-ISI relies upon the plant IGSCC Program to determine which components are IGSCC-resistant (Category A). All components included in the plant IGSCC Program and categorized as Category B or lower will be considered susceptible to IGSCC.

TGSCC – Ruled out either due to a lack of susceptible material or a lack of initiating contaminants (per EPRI BWR Water Chemistry Guidelines).

ECSCC – Ruled out either due to a lack of susceptible material or due to compliance with [13] and a lack of concentrated chloride bearing sources.

PWSCC – Ruled out due to the fact that this mechanism only affects PWRs.

MIC – Ruled out due to high operating temperatures and reactor-grade water.

PIT – Ruled out due to lack of initiating contaminants, per EPRI BWR Water Chemistry Guidelines.

CC – Per Section 5.3.3.2.2, the feedwater inlet nozzles and isolation condenser return nozzles have thermal sleeves. Per Table 1.11-1 (Action Plan Item/Issue Number A-42), the ESBWR design eliminates crevice conditions. Therefore, even in locations where thermal sleeves exist, they would not be considered geometric crevices and would therefore not be susceptible to CC.

E-C – Ruled out due to lack of potential cavitation sources.

FAC – EPRI RI-ISI defers to the plant FAC Program for management of this mechanism. It is possible that some ESBWR FWS components will be monitored under the plant FAC Program, however, these locations would most likely be far removed from the RCPB portion of the feedwater system.

Therefore, TT and IGSCC are the only potentially active degradation mechanisms in the RCPB of the ESBWR design.

In summary, the above discussion illustrate that the degradation mechanism part of the RI-ISI methodologies can be reliably applied to the New Build fleet. Similar to the consequence assessment, as the plant enters operation, various inputs (e.g. updated operating procedures) to the degradation mechanism evaluation should be reviewed and the evaluation updated if necessary. Note: this updating process is a key component of the RI-ISI methodology.

Risk Ranking and Element Selection

As previously discussed, when using the EPRI RI-ISI traditional methodology, each segment is placed onto the appropriate location on the EPRI Risk Characterization Matrix. [Note: segments are defined as runs of piping with the same consequence of failure and same failure potential (i.e. degradation mechanism susceptibility)]. This matrix is based on three broad categories of failure potential and four broad categories of consequence potential. Several Risk Categories are identified, which are subsequently combined into three risk regions (low, medium or high) for more robust and efficient utilization.

For Risk Category 1, 2, or 3, at least 25% of the elements belonging to each category are selected for inspection. For Risk Category 4 or 5, at least 10% of the elements are selected for inspection. Piping located in Risk Category 6 or 7 do not required NDE inspections.

When applying the EPRI Streamlined RI-ISI methodology to RCPB piping, risk ranking, and element selection are essentially the same as the EPRI Traditional approach. Results for the New Build designs are provided in the following figures. As with the consequence assessment and degradation mechanism evaluation steps, the risk ranking results are similar but not identical to the existing fleet. Again, because of steps taken in the design stage, the consequence ranking is somewhat lower for the New Build designs as compared to the existing fleet; and the number and extent of possible degradation identified is less for the New Build designs as compared to the existing fleet.

Given the above, as expected, the amount of piping appearing in the high risk region (i.e. risk categories 1, 2, and 3) is less and the amount of piping in the medium and low risk regions (i.e. risk categories 4, 5, 6 and 7) is more.

In contrast to the traditional RI-ISI methodology, the streamlined RI-ISI methodology defines a minimum number of inspections regardless of risk significance. For example, ten percent of the reactor coolant pressure boundary shall be selected for inspection, no matter how small the risk numbers are from the PRA perspective. This rule provides an additional level of defense in depth for new plant designs.

ABWR		Consequence Rank			
		None	Low	Med	High
DM Potential	High	RC 7 No	RC 5 No	RC 3 No	RC 1 No
	Med	RC 7 No	RC 6 No	RC 5 Yes	RC 2 Yes
	Low	RC 7 No	RC 6 Yes	RC 5 Yes	RC 4 Yes

Figure 3-1
ABWR Risk Ranking Results

AP1000		Consequence Rank			
		None	Low	Med	High
DM Potential	High	RC 7 No	RC 5 No	RC 3 No	RC 1 No
	Med	RC 7 No	RC 6 No	RC 5 Yes	RC 2 Yes
	Low	RC 7 No	RC 6 Yes	RC 5 Yes	RC 4 Yes

Figure 3-2
AP1000 Risk Ranking Results

EPR (US)		Consequence Rank			
		None	Low	Med	High
DM Potential	High	RC 7 No	RC 5 No	RC 3 No	RC 1 No
	Med	RC 7 No	RC 6 No	RC 5 Yes	RC 2 Yes
	Low	RC 7 No	RC 6 Yes	RC 5 Yes	RC 4 Yes

Figure 3-3
EPR Risk Ranking Results

APWR		Consequence Rank			
		None	Low	Med	High
DM Potential	High	RC 7 No	RC 5 No	RC 3 No	RC 1 No
	Med	RC 7 No	RC 6 No	RC 5 Yes	RC 2 Yes
	Low	RC 7 No	RC 6 Yes	RC 5 Yes	RC 4 Yes

Figure 3-4
APWR Risk Ranking Results

ESBWR		Consequence Rank: None	Low	Med	High
DM Potential	High	RC 7 No	RC 5 No	RC 3 No	RC 1 No
	Med	RC 7 No	RC 6 No	RC 5 Yes	RC 2 Yes
	Low	RC 7 No	RC 6 Yes	RC 5 Yes	RC 4 Yes

Figure 3-5
ESBWR Risk Ranking Results

Risk Impact Assessment

As with all risk-informed applications, the impact of the risk-informed application on plant risk needs to be determined [3]. For both the EPRI Traditional and Streamlined RI-ISI methodologies, this is accomplished by showing that the changes in risk due to changes in the number and locations of the inspections do not pose a significant adverse risk impact as determined by changes in CDF or LERF. The risk impact assessment process may involve one or more of the following: application of qualitative criteria, bounding estimates of risk impacts, realistic estimates of risk impacts, and/or adjustments to the selection of elements to meet the risk acceptance criteria.

The acceptance criteria consist of plant level and system level acceptance criteria founded upon Regulatory Guide 1.174 [3] and is documented in EPRI TR-112657 [1]. The criteria are as follows:

Plant Level:	System Level:
< 1E-06 CDF	< 1E-07
< 1E-07 LERF	< 1E-08

In discussion with NRC staff, for New Build, alternate criteria are being investigated on two fronts. First, an additional risk metric may need to be defined and evaluated. This metric, large release frequency (LRF), is being discussed among the industry (NEI, Vendors, COL applicant, NRC) and is not yet defined. However, given how the above RI-ISI methodologies have been developed with CDF and LERF already addressed, along with defense in depth considerations and safety margin requirements, it is not expected that inclusion of a LRF metric will substantially impact a RI-ISI program.

Secondly, NRC and industry are discussing the possibility of more limited acceptance criteria for risk-informed applications, including RI-ISI programs. That is, smaller risk increases would be allowed for New Build plants as compared to the existing fleet. Again, it is anticipated that given how the above RI-ISI methodologies have been developed, including the risk impact assessment portion, if new, more restrictive acceptance criteria are required; there will not be a significant impact on the RI-ISI program results (i.e. on the number of inspections).

At this point in time, the USNRC staff has issued SECY-10-0121 [14]. In this SECY, staff has recommended to the Commissioners to not include a new risk metric (e.g. LRF) for new reactors while providing guidance "*for risk-informed licensing-basis changes that would prevent a significant decrease in the new reactor's level of safety.*" As discussed above, for RI-ISI programs developed in accordance with the EPRI RI-ISI methodologies, this approach is not expected to impact the RI-ISI results in any substantial manner.

4
PRA TECHNICAL ADEQUACY AND TIMING CONSIDERATIONS

Risk-informed methodologies have been developed in order to establish alternative in-service inspection requirements. Plant-specific PRAs are typically used during the RI-ISI development to support the consequence assessment, risk ranking, element selection, and delta risk evaluation steps.

With respect to PRA technical adequacy, the ASME PRA Standard has been developed (ASME RA-Sb-2005); and the NRC Regulatory Guide (RG) 1.200 R1 and R2 were issued, providing a review and endorsement (with positions) of the PRA Standard.

With respect to risk-informed applications, Section 3 of the PRA Standard provides a roadmap for determining the capability of a PRA needed to support a particular risk-informed application. Key aspects of this roadmap include the following:

- Role of the PRA in the application and extent of reliance of the decision on the PRA results
- Risk metrics to be used to support the application and associated decision criteria
- Significance of the risk contribution from the hazard group to the decision
- Degree to which bounding or conservative methods for the PRA or in a given portion of the PRA would lead to inappropriately influencing the decisions made in the application, also approaches for accounting for this possibility in the decision-making process
- Degree of accuracy and evaluation of uncertainties and sensitivities required of the PRA results
- Degree of confidence in the results that are required to support the decision
- Extent to which the decisions made in the application will impact the plant design basis

Each of these aspects is discussed in detail in EPRI TR-112657 [1], which provides the foundation for the EPRI traditional RI-ISI approach and the EPRI streamlined RI-ISI approach codified in ASME Code Case N716.

In parallel with this report, EPRI report 1021467 [15] has been developed. It provides guidance as to the capability categories for each supporting requirement that is applicable to RI-ISI applications. RI-ISI applications using the EPRI traditional RI-ISI approach do not use the internal flooding (IF) directly as such IF supporting requirements are not applicable and Section 3.3 of EPRI Report TR-112657 is the appropriate resource. This is in contrast to the EPRI streamlined RI-ISI approach, which uses the internal flooding study directly.

For the purposes of RI-ISI, the capability category relates to the technical aspects of the plant PRA; and so peer review findings and/or gaps related to documentation that do not impact the results would allow the capability category to still be considered met.

As can be seen in [15], for many of the supporting requirements, there is no differentiation between capability categories. That is, the requirements of the Standard have the same wording for all three capability categories. Additionally, 22 supporting requirements were identified as not applicable to the EPRI traditional RI-ISI approach; and 23 supporting requirements were identified as not applicable to the EPRI streamlined RI-ISI approach and, therefore, need not be met.

As discussed in [15], with respect to the influence of RG1.200 revision2 (i.e. hazards groups) on RI-ISI program development, it is important to note that the RI-ISI supporting analyses (e.g. consequence assessment) are based upon the internal events PRA. The purpose of developing a RI-ISI program is to define an alternative in-service inspection strategy for piping systems (e.g. NDE of a piping weld). The use of the internal events PRA only can be justified by the following:

- The very small changes in the potential for piping failure due to changes in ISI, when augmented inspection programs for FAC, IGSCC-BWR categories B through G, and localized corrosion such as MIC are left unchanged or improved
- The small contribution of piping failure, which would be influenced by changes in ISI, to the risk attributable to external events such as fire
- The use of defense in depth and safety margin to provide additional assurance of piping integrity

The conclusion drawn in [15] is that quantification of other hazard groups will not change the conclusions derived from the RI ISI process. As such, EPRI 1021467 guidance on meeting Regulatory Guide 1.200, revision 1 and Regulatory Guide 1.174 is sufficient for developing RI-ISI programs. Based on RG 1.174:

- The magnitude of the potential risk impact is not significant.
- Traditional engineering arguments including defense in depth and safety margin are applied.
- Including other hazard groups would not affect the decision: that is, they would not alter the results of the comparison with the acceptance guidelines.

With respect to application to New Build, application of the EPRI Traditional RI-ISI method results in the subject piping being classified into seven risk categories (1 through 7). Consistent with ASME BPV Code, Appendix R, risk categories 1 through 5 are considered high safety significant (HSS). Also, consistent with Appendix R, piping classified as HSS should be subjected to preservice inspection (PSI). Piping classified as Low Safety Significant (LSS) does not require PSI. ASME Code Case N716 (EPRI Streamlined RI-ISI method) contains explicit PSI criteria.

As to the PRA itself, the ASME PRA Standard was originally developed in response to operating reactors. As such, there are a number of supporting requirements that are not achievable early in the plant design while there are others that can be achieved as the plant approaches operation and finally some others that can not be fully achieved until after plant operation. In recognition of this situation, there is an ASME ALWR working group currently developing guidance on this matter with the ultimate goal of a revision to the PRA Standard.

With respect to RI-PSI and RI-ISI program development, Table 4-1 provides a listing of supporting requirements (SRs) that have a variable degree of achievability during the transition from a DCD PRA to a COL PRA and finally to a fully operational plant PRA. Of the SRs listed in the table, 6 SRs need not be met in order to support the development of a RI-ISI/RI-PSI program. Of the remaining SRs listed in the table, 17 can be met for RI-ISI/PSI purposes, 29 can be fully (28) or mostly (1) met at Fuel Load and 23 can be fully met by the first inspection period (e.g. obtaining operating and maintenance data).

The operating fleet has extensive experience with RI-ISI and RI-PSI. This experience covers not only initial development of the RI-ISI program but numerous updates (periodic and interval updates) including re-submittal of the updated program to NRC for review and approval. This experience provides several advantages to the New Build fleet with respect to understanding the impact of a DC/COL PRA versus an operational plant PRA on RI-ISI/RI-PSI programs. Every plant that has implemented a RI-ISI program (~90 % of the U.S, industry) has done so on piping that was not subjected to PSI per the ISI requirements defined in the RI-ISI program. Examples of this lack of PSI are as follows:

- Class 1 only RI-ISI applications: Examination categories B-F and B-J require a volumetric PSI examination be conducted on larger bore piping (e.g. $\geq$ 4 NPS). This examination is consistent with some, but not all, RI-ISI required examinations for large bore piping (e.g. volumes may be different). Additionally, smaller bore piping (< 4 NPS), which some RI-ISI applications have shown to be safety significant, are subjected to an outside diameter surface only PSI examination. Per RI-ISI, if this piping is selected for inspection (e.g. for thermal fatigue), a volumetric examination is required. Thus, as with some large bore locations, the PSI provides no benefit.
- Class 1 and 2 RI-ISI applications: In addition to the above discussion on Class 1 piping, only 7.5 percent of Class 2 piping receives any PSI at all. Thus, many Class 2 locations selected for inspection per the RI-ISI program were not previously subject to a PSI examination.
- Full scope RI-ISI applications: Experience has shown that RI-ISI inspections were conducted on Code (e.g. Class 3) and non-Code (e.g. non safety-related) piping that had not received a PSI examination.

Thus, having a PSI conducted on every location that will be subjected to a RI-ISI inspection is not necessary. This experience and position is also consistent with criteria contained in Appendix R.

RI-ISI and RI-PSI programs also have unique aspects that are different from a number of other risk-informed initiatives. For example, the RI-ISI inspection population is spread out over a ten year inspection interval. There are minimum and maximum requirements as to how many inspections can be credited. That is, in the first inspection period, a minimum of 16 percent of the population must be inspected; but no more than 50 percent can be credited. For the second inspection period, a minimum of 50 percent of the population must be inspected; but no more than 75 percent can be credited; and for the third (final) period, all remaining inspections must be completed to reach 100 percent of the inspection population.

The RI-ISI program also has a living program component. This component requires that periodic and interval based updates be conducted, and the inspection population adjusted accordingly. As such, if a supporting requirement could not be met until the first inspection period is completed (e.g. DA-C2), the RI-ISI process requires that the RI-ISI analyses be updated to reflect this new information. If this new information increases or decreases the inspection population, the necessary change (addition or deletion of inspections) will be implemented over the remaining two inspection periods thereby completing 100 percent of the inspection population by the end of the first inspection interval.

Finally, because of how the EPRI RI-ISI methodologies have been built - absolute ranking and large thresholds for binning consequence ranking with the Traditional method and conservative identification of HSS for the Streamlined method that includes all Class 1 and large bore BER - only large changes in the PRA would be expected to have an impact on the RI-ISI results and therefore any significant changes to the RI-ISI by PRA updates are not expected. This expectation has been borne out by numerous updates conducted on the operating fleet, including a number of plants that have upgraded their PRAs to better meet the requirements in the PRA standard.

One additional lesson learned from the operating fleet that provides further confidence in the stability of the New Build fleet RI-ISI programs is that all of the Part52 plants (DCDs and COLAs) have committed to meeting SRP sections 3.6.1 and 3.6.2 [5]. Meeting the requirements contained in these two sections of the SRP provides for a robust design from a spatial separation perspective.

As such, meeting the guidelines of [15] will provide for the development of robust RI-PSI/ISI programs.

Table 4-1
PRA Technical Adequacy Assessment – Timing Considerations

Sec ID 2008 (2009)	PRA Std / RG 1.200 Assessment	TR1021467 Assessment	TR102467 Requirement
IE-A3 (IE-A3)	Plant-specific data may not be available Can be met at 1st Period	Plant-specific data may not be available Can be met at 1st Period	CCI/II/III
IE-A3a (IE-A4)	CCI/II can be met partially as some components may be unique	CCI/II can be met partially as some components may be unique Will be met via the RI-ISI living program component	CC I/II
IE-A4a (IE-A6)	CC II and III need routine alignment information that may not be available until plant operation	CC I can be met	CC I
IE-A6 (IE-A8)	CCII and III require interviews of “plant personnel” who may not be assigned until post-DC PRA	CCI can be met	CC I
IE-A7 (IE-A9)	CCII and III require review of plant-specific operating experience that may not be available until 1st Period	CCI can be met	CC I
IE-C1 (IE-C1)	Plant-specific data may not be available until 1st Period. “Relevant” generic data needs to be selected.	Need not be met	Need not be met
IE-C1a (IE-C2)	Plant-specific data may not be available until 1st Period	Need not be met	Need not be met
IE-C1b (IE-C3)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CCI/II/III
IE-C2 (IE-C4)	Plant-specific data may not be available until 1st Period	Need not be met	Need not be met
IE-C3 (IE-C5)	CC I/II could be met by using an assumption CCIII can not be met until 1st Period	Need not be met	Need not be met
IE-C5 (IE-C7)	CC III can not be met until 1st Period	Need not be met	Need not be met
IE-C9 (IE-C11)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CCI/II/III

Table 4-1 (continued)
PRA Technical Adequacy Assessment – Timing Considerations

Sec ID 2008 (2009)	PRA Std / RG 1.200 Assessment	TR1021467 Assessment	TR102467 Requirement
IE-C12 (IE-C14)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II
AS-A5 (AS-5)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III
AS-B5a (AS-B6)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III
SC-A6	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III
SY-A2 (SY-A2)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III
SY-A3 (SY-A3)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III
SY-A4 (SY-A4)	Plant staff / operating data staff may not be available Can be mostly met at Fuel Load and completely met at 1st Period	Plant staff / operating data may not be available Can be mostly met at Fuel Load and completely met at 1st Period	CC I
SY-A5 (SY-A5)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III
SY-A7 (SY-A7)	Detailed design information may not be available Can be met at Fuel Load	Detailed design information may not be available Can be met at Fuel Load	CC I/II
SY-A18 (SY-A19)	Operating experience may not be available Can be met at 1st Period	Operating experience may not be available Can be met at 1st Period	CC I/II/III
SY-A18a (SY-A20)	Operating experience and Procedures may not be available Can be met at 1st Period	Operating experience and Procedures may not be available Can be met at 1st Period	CC I/II/III
HR-A1 (HR-A1)	Operating experience and procedures may not be available Can be met at 1st Period	Operating experience and procedures may not be available Can be met at 1st Period	CC I/II/III
HR-A2 (HR-A2)	Operating experience and procedures may not be available Can be met at 1st Period	Operating experience and procedures may not be available Can be met at 1st Period	CC I/II/III

Table 4-1 (continued)
PRA Technical Adequacy Assessment – Timing Considerations

Sec ID 2008 (2009)	PRA Std / RG 1.200 Assessment	TR1021467 Assessment	TR102467 Requirement
HR-A3 (HR-A3)	Operating experience and procedures may not be available Can be met at 1st Period	Operating experience and procedures may not be available Can be met at 1st Period	CC I/II/III
HR-C3 (HR-D3)	Operating experience and procedures may not be available Can be met at 1st Period	Operating experience and procedures may not be available Can be met at 1st Period	CC I/II/III
HR-D3 (HR-D3)	For CC II/III plant procedures may not be available	CC I can be met	CCI
HR-D4 (HR-D4)	Procedures may not be available Note: SR is only relevant if applicable Can be met at Fuel Load	Procedures may not be available Note: SR is only relevant if applicable Can be met at Fuel Load	CC I/II/III
HR-D7 (HR-D7)	CCI/II can be met	CCI/II can be met	CC I/II
HR-E1 (HR-E1)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III
HR-E2 (HR-E2)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III
HR-E3 (HE-E3)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I
HR-E4 (HR-E4)	CCII/III require use of "simulator observations or talk-throughs…" that may not be possible until post DC PRA	CC I can be met	CC I
HR-F2 (HR-F2)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I
HR-G3 (HR-G3)	For CC II/III plant procedures may not be available Can be met at Fuel Load	CC I can be met	CC I
HR-G5 (HR-G5)	For CC II and III plant procedures may not be available or walkdowns / talkthroughs may not be possible Can be met at Fuel Load	CC I can be met	CC I

Table 4-1 (continued)
PRA Technical Adequacy Assessment – Timing Considerations

Sec ID 2008 (2009)	PRA Std / RG 1.200 Assessment	TR1021467 Assessment	TR102467 Requirement
HR-G6 (HR-G6)	Procedures and operating experience may not be available Can be met at 1st Period	Procedures and operating experience may not be available Can be met at 1st Period	CC I/II/III
HR-G7 (HR-G7)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III
HR-H2 (HR-H2)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III
DA-B2 (DA-B2)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II
DA-C2 (DA-C2)	Plant-specific data may not be available Can be met at 1st Period	Plant-specific data may not be available Can be met at 1st Period	CC I/II/III
DA-C3 (DA-C3)	Plant-specific data may not be available Can be met at 1st Period	Plant-specific data may not be available Can be met at 1st Period	CC I/II/III
DA-C4 (DA-C4)	Plant-specific data may not be available Can be met at 1st Period	Plant-specific data may not be available Can be met at 1st Period	CC I/II/III
DA-C5 (DA-C5)	Plant-specific data may not be available Can be met at 1st Period	Plant-specific data may not be available Can be met at 1st Period	CC I/II/III
DA-C6 (DA-C6)	Plant-specific data may not be available Can be met at 1st Period	Plant-specific data may not be available Can be met at 1st Period	CC I/II/III
DA-C7 (DA-C7)	Plant-specific data may not be available Can be met at 1st Period	CCI can be met	CC I
DA-C8 (DA-C8)	CCII/III require review of plant-specific operating experience Can be met at 1st Period	CCI can be met	CC I
DA-C9 (DA-C9)	Plant-specific data may not be available Can be met at 1st Period	Plant-specific data may not be available Can be met at 1st Period	CC I/II

Table 4-1 (continued)
PRA Technical Adequacy Assessment – Timing Considerations

Sec ID 2008 (2009)	PRA Std / RG 1.200 Assessment	TR1021467 Assessment	TR102467 Requirement
DA-C10 (DA-C10)	Plant-specific data may not be available Can be met at 1st Period	Plant-specific data may not be available Can be met at 1st Period	CC I
DA-C11 (DA-C11)	Plant-specific data may not be available Can be met at 1st Period	Plant-specific data may not be available Can be met at 1st Period	CC I/II/III
DA-C12 (DA-C13)	Plant-specific data may not be available Can be met at 1st Period	Plant-specific data may not be available Can be met at 1st Period	CC I
DA-C13 (DA-C14)	Plant-specific data may not be available Can be met at 1st Period	Plant-specific data may not be available Can be met at 1st Period	CC I/II/III
DA-C14 (DA-C15)	Plant-specific data may not be available Can be met at 1st Period	Plant-specific data may not be available Can be met at 1st Period	CC I/II/III
DA-D1 (DA-D1)	CCII and III require review of plant-specific operating experience Can be met at 1st Period	CC I can be met	CC I
DA-D2 (DA-D2)	Can be met. This SR also shows that other Data SRs may be supplemented by this approach	Can be met. This SR also shows that other Data SRs may be supplemented by this approach	CC I/II/III
DA-D4 (DA-D4)	For CC II/III, plant specific data may not be available Can be met at 1st Period	CCI can be met	CC I
IF-A3 (IFPP-A4)	As-built and as-operated sources may not be available As-built can be met at Fuel Load As-operated can be met at 1st Period	As-built and as-operated sources may not be available As-built can be met at Fuel Load As-operated can be met at 1st Period	CC I/II/III
IF-A4 (IFPP-A5)	Walkdowns may not be possible Can be met at Fuel Load	Walkdowns may not be possible Can be met at Fuel Load	CC I/II/III
IF-B3a (IFSO-A6)	Walkdowns may not be possible Can be met at Fuel Load	Walkdowns may not be possible Can be met at Fuel Load	CC I/II/III

Table 4-1 (continued)
PRA Technical Adequacy Assessment – Timing Considerations

Sec ID 2008 (2009)	PRA Std / RG 1.200 Assessment	TR1021467 Assessment	TR102467 Requirement
IF-C6 (IFSN-A14)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC II
IF-C8 (IFSN-A16)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC II
IF-C9 (IFSN-A17)	Walkdowns may not be possible Can be met at Fuel Load	Walkdowns may not be possible Can be met at Fuel Load	CC I/II/III
IF-D5a (IFEV-A6)	Noted information may not be fully available Most can be met at Fuel Load, Operating data can be met at 1st Period	Noted information may not be fully available Most can be met at Fuel Load, Operating data can be met at 1st Period	CC II/III
IF-D6 (IFEV-A7)	Maintenance procedures and experience may not be available Most can be met at Fuel Load, Operating data can be met at 1st Period	Need not be met	Need not be met
IF-E5a (IFQU-A6)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III
IF-E8 (IFQU-A11)	Walkdown may not be possible Can be met at Fuel Load	Walkdown may not be possible Can be met at Fuel Load	CC I/II/III
QU-D1b (QU-D2)	Procedures and operating experience may not be available Can be met at 1st Period	Procedures and operating experience may not be available Can be met at 1st Period	CC I/II/III
QU-D3 (QU-D4)	CCII/III require review of similar plant results which may not be available	CC I can be met	CC I
LE-C2a (LE-C2)	For CC II/III procedures may not be available Can be met at Fuel Load	CC I can be met	CC I
LE-C2b (LE-C3)	For CC II/III applicability of available generic data needs to be confirmed.	CC I can be met	CC I
LE-C3 (LE-C4)	For CC II and III applicability of available generic calculations needs to be confirmed	CCI can be met	CC I

Table 4-1 (continued)
PRA Technical Adequacy Assessment – Timing Considerations

Sec ID 2008 (2009)	PRA Std / RG 1.200 Assessment	TR1021467 Assessment	TR102467 Requirement
LE-C6 (LE-C7)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III
LE-D5 (LE-D6)	Procedures may not be available BWR – Not applicable PWR – Can be met at Fuel Load	Procedures may not be available BWR – Not applicable PWR – Can be met at Fuel Load	CC I
LE-E1 (LE-E1)	Procedures may not be available Can be met at Fuel Load	Procedures may not be available Can be met at Fuel Load	CC I/II/III

5 REGULATORY APPROVAL STRATEGY

The vast majority of the operating fleet has implemented a RI-ISI program. Other than the early pilot plant applications, each of these RI-ISI programs have been submitted and approved via the relief request process. That process is pursuant to Title 10 of the *Code* of *Federal Regulations* 10 CFR 50.55a(a)(3)(i).

For the New Build fleet, as discussed in various documents (e.g. section 5.4.2.8 of [16]), relief requests can be filed as necessary in accordance with 10 CFR 50.55a(a)(3).

In parallel with the above, work is underway to have both EPRI RI-ISI methodologies approved for generic use by NRC thereby obviating the need for plant-specific 50.55a relief requests. By letter dated April 9, 2009, the USNRC accepted for review EPRI Report 1018427 [Note: this report is now numbered 1021467 [15] and will be published in 2011]. As stated in this letter, the goal of this report and NRC acceptance is to support two generic regulatory improvement efforts. The first effort is NRC's review of ASME Boiler and Pressure Vessel Code, Appendix R "Risk-informed Inservice Inspection for Piping" for endorsement in 10CFR50.55a, "Codes and Standards." This appendix contains the EPRI traditional RI-ISI methodology. The second effort is NRC's review ASME Code Case N716 "Alternative Piping Classification and Examination Requirements Based upon Risk-informed and Safety Based Insights" for endorsement in Regulatory Guide 1.147, "Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1.

Once this generic effort has been completed, plants referencing the applicable 10CFR or Regulatory Guide version (e.g. section 5.24 of [16]) will be able to use these RI-ISI methodologies without requiring a submittal or NRC prior approval.

6
SUMMARY AND CONCLUSIONS

The EPRI RI-ISI methodologies were reviewed against the various new plant designs to determine the viability of developing risk-informed PSI and ISI programs. While there were no substantial roadblocks identified there were issues that will need to be addressed. These issues are listed as follows:

- While not explicitly identified by this review, if there are new materials to be used in these new plant designs, there could be questions as to the reliability of this material going forward. Based upon discussion with the ASME Working Group on the Implementation of Risk-Based Examination, the following additional requirements should be used in the application of the RI-ISI methodologies, in both the traditional and streamlined approaches.

  For combinations of material type and service condition with less than 10 years of operating experience, the sample shall be at least 25% of the locations (e.g. welds) containing the material.

  This value of a 25% inspection population is consistent with current deterministic requirements for examination category B-J. It is anticipated that once significant, reliable operational history has been obtained for these new materials, this requirement can be re-visited and possibly less restrictive inspection requirements defined.

- Alternate decision criteria for New Build plants are being investigated by NRC staff. That is, an additional risk metric may need to be defined and evaluated. This metric, large release frequency (LRF), is being discussed among the industry (NEI, Vendors, COL applicant, and NRC) and is so far undefined. However, given how the above RI-ISI methodologies have been developed (e.g. CDF and LERF already address defense-in-depth considerations and safety margin requirements), it is not expected that inclusion of a LRF metric will substantially impact a RI-ISI program.

- NRC and industry are discussing the possibility of more limited acceptance criteria for risk-informed applications, including RI-ISI programs. That is, smaller risk increases would be allowed for New Build plants as compared to the existing fleet. Again, it is anticipated that given how the above RI-ISI methodologies have been developed, including the risk impact assessment portion, if new, more restrictive acceptance criteria are required, there will not be a significant impact on the RI-ISI program results in terms of the number of inspections.

- At this point in time, the USNRC staff has issued SECY-10-0121 [14]. In this SECY, staff has recommended the Commissioners not include a new risk metric (e.g. LRF) for new reactors while providing guidance "*for risk-informed licensing-basis changes that would prevent a significant decrease in the new reactor's level of safety.*" As discussed above, for RI-ISI programs developed in accordance with the EPRI RI-ISI methodologies, this approach is not expected to impact the RI-ISI results in any substantial manner.

- PRA technical adequacy is a key component in developing a robust RI-ISI program. EPRI developed guidance is currently being reviewed by NRC and is expected to be issued early 2011. However, there remains an issue unique to the New Build fleet in that a subset of the PRA can not be completed until the plant is operating (e.g. operating data not available). This report identifies those parts of the PRA that can not be completed and provides a basis why a robust RI-ISI program can still be developed.
- In the short term, implementation of a RI-ISI program for the New Build fleet can be done in a manner consistent with that of the operating fleet. That is, as discussed in various documents (e.g. 5.4.2.8 of [16]), relief requests can be filed in accordance with 10 CFR 50.55a(a)(3) as necessary.
- Finally, work is underway to have both EPRI RI-ISI methodologies approved for generic use by NRC thereby obviating the need for plant-specific 50.55a relief requests. The first effort is NRC's review of ASME Boiler and Pressure Vessel Code, Appendix R "Risk-informed Inservice Inspection for Piping" for endorsement in 10CFR50.55a, "Codes and Standards." This appendix contains the EPRI traditional RI-ISI methodology. The second effort is NRC's review ASME Code Case N716 "Alternative Piping Classification and Examination Requirements Based upon Risk-informed and Safety Based Insights" for endorsement in Regulatory Guide 1.147, "Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1.

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3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
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