

ATTACHMENT 71111.08

INSPECTABLE AREA: Inservice Inspection Activities

CORNERSTONES: Initiating Events (45%)
Barrier Integrity (45%)
Mitigating Systems (10%)

EFFECTIVE DATE: January 1, 2012

INSPECTION BASES: Inservice inspection (ISI) activities can detect precursors to pressure boundary failures in reactor coolant systems (RCS), emergency core cooling systems (ECCS), risk-significant piping and components, and containment systems. Degradation of pressure retaining components in these systems would result in a significant increase in risk. This inspection is intended to assess the effectiveness of the licensee's program for monitoring degradation of vital system boundaries.

The scope of this inspectable area is limited to the following structures, systems, and components (SSCs):

- (1) Reactor coolant system, including steam generator tubes in pressurized water reactors (PWRs).
- (2) Piping connected to the RCS, failure of which could result in an interfacing system loss of coolant accident.
- (3) Reactor vessel internals.
- (4) Risk-significant piping system boundaries.
- (5) Containment system boundaries (including coatings and post-tensioning systems, where applicable).

LEVEL OF EFFORT: Inspections are to be performed during each refueling outage at each reactor unit at a site. The level of ISI activities including steam generator inspections at each plant can vary significantly from outage to outage but typically should be as identified in this procedure. Since all activities are subject to outage availability, inspectors must make a reasonable effort to ensure that the inspection effort occurs during the time that the activities are scheduled.

71111.08-01 INSPECTION OBJECTIVE

To assess the effectiveness of the licensee's program for monitoring degradation of the reactor coolant system boundary, risk-significant piping system boundaries, and the containment boundary.

Issue Date: 11/23/11

Effective Date: 01/01/12

02.01 Non-destructive Examination (NDE) Activities and Welding Activities.

- a. Review a sample of NDE activities. The review sample should consist of two or three types of NDE activities, including at least one volumetric examination.
- b. Order of preference for reviewed NDE activities:
 1. Volumetric examinations
 2. Surface examinations
 3. **Containment visual examinations (as required by IWE/IWL)**
 4. Visual examinations (VT-1 and/or VT-3 on risk significant components)
- c. For each examination reviewed, perform the following through either direct observation (preferred method) or record review:
 1. For ASME Code Required Examinations:
 - (a) Verify that NDE activities are performed in accordance with ASME Boiler and Pressure Vessel Code requirements.
 - (b) Verify that indications and defects, if present, are dispositioned in accordance with the ASME Code or an NRC approved alternative (e.g. approved relief request).
 - (c) Verify that relevant indications are compared to previous examinations to determine if any changes have occurred.
 2. For Other Augmented or Industry Initiative Examinations.
 - (a) Verify the activities are performed in accordance with the licensee's augmented inspection program and associated examination procedure (e.g., examinations of components such as vessel internals subject to fatigue, intergranular stress corrosion or irradiation assisted stress corrosion, feedwater pipe subject to flow-accelerated corrosion, nickel based weldments subject to primary water stress corrosion cracking etc).
 - (b) Verify indications and defects, if present, are dispositioned in accordance with licensee's procedures and NRC requirements.
 - (c) Verify the activities are performed in accordance with applicable industry guidance documents and NRC commitments. For deviations with possible safety implications, the inspector should inform the applicable NRR branch.
- d. If applicable, review at least one volumetric or surface examination from the previous outage with relevant indication(s) that were analytically evaluated and accepted by the licensee for continued service. Verify that the licensee's acceptance was in accordance with the ASME Code or an NRC approved alternative, and confirm the indication(s) were examined for acceptability for continued service.

- e. If applicable, for modifications, repairs, or replacements consisting of welding on pressure boundary risk significant systems, verify for one to three welds that the welding activities, and any applicable NDE performed, were performed in accordance with ASME Code requirements, or an NRC approved alternative.

02.02 PWR Vessel Upper Head Penetration (VUHP) Inspection Activities.

Section 02.02 is a requirement of the Davis Besse Lesson Learned Task Force (DBLLTF) No. 3.3.4(3): Develop inspection guidance or revise existing guidance to ensure that the vessel head penetration (VHP) nozzles and the reactor pressure vessel (RPV) head area are periodically reviewed by the NRC during licensee ISI activities. [C-1]

- a. The inspection requirement steps in 02.02 parallel the inspection requirement steps in 02.01. The inspection of the licensee's reactor VUHP activities under 02.02.a and b may be considered as satisfying the corresponding inspection requirements of 02.01.a and b.

If the licensee is performing a bare metal visual examination (VE) of the VUHPs, review the examination procedure; and either observe portions of this examination, or review the post examination records. Review licensee criteria for confirming visual examination quality and instructions for resolving interference or masking issues to confirm they are consistent with 10 CFR 50.55a(g)(6)(ii)(D).

And/or;

If the licensee is performing non-visual nondestructive examination (NDE) of the reactor vessel head, review a sample of these examinations. In particular, review the NDE examination results and procedures used to confirm that they meet Code Case N-729-1. Confirm that the ultrasonic examination procedures and equipment used were qualified by blind demonstration test in accordance with 10 CFR 50.55a(g)(6)(ii)(D).

And

Review the records recording the extent of inspection for each penetration nozzle including documents which resolved interference or masking issues to confirm that the extent of examination meets 10 CFR 50.55a(g)(6)(ii)(D). Specifically, for the penetration locations reviewed:

1. For VEs, confirm the coverage has been achieved and that limitations in coverage are properly recorded.

And/or;

2. For non-visual NDE, confirm that essentially 100 percent (i.e. greater than or equal to 90 percent) of the required examination volumes and surfaces **were examined**. Additionally, confirm that a volumetric (i.e. ultrasonic examination - backwall leakage pattern) or surface leakage path examination assessment (i.e. wetted J-groove weld surface eddy current or dye penetrant examination) was completed.

- b. For each NDE activity reviewed, perform the following through either direct observation (preferred method) or record review:
 1. Verify that the activities are performed in accordance with the requirements of 10 CFR 50.55a(g)(6)(ii)(D).
 2. Verify that indications and defects, if detected, were dispositioned in accordance with 10 CFR 50.55a(g)(6)(ii)(D).
- c. If relevant indications have been identified that were accepted for continued service, review a sample of the examination records and associated evaluations accepting these conditions. Verify that the licensee's acceptance for continued service was in accordance with 10 CFR 50.55a(g)(6)(ii)(D) or an NRC approved alternative.
- d. If welding repairs have been completed on upper head penetrations, review a sample of these repairs. Verify that the welding process and welding examinations were performed in accordance with ASME Code requirements and 10 CFR 50.55a(g)(6)(ii)(D) or an NRC approved alternative.

02.03 Boric Acid Corrosion Control (BACC) Inspection Activities (PWRs)

Section 02.03 is a requirement of the Davis Besse Lesson Learned Task Force (DBLLTF) No. 3.3.2(1): Develop inspection guidance for the periodic inspection of Pressurized Water Reactors (PWR) plant boric acid corrosion control programs. [C-2]

- a. Perform an independent review of plant areas that have recently received a boric acid walkdown by the licensee, through either direct observation (preferred method) or record review. (Reference **Inspection Procedure (IP) 71111.20**) **to determine if visual inspections emphasized locations where boric acid leaks can cause degradation of safety significant components. Also, verify that degraded or non-conforming conditions were identified properly in the licensee's corrective action program.**
- b. Review one to three engineering evaluations performed for boric acid found on RCS piping and components **to determine if the licensee properly applied applicable corrosion rates to affected components and properly assessed the effects of corrosion induced wastage on structural or pressure boundary integrity.**
- c. Review one to three corrective actions performed for evidence of boric acid leaks identified. Confirm that these corrective actions were consistent with requirements of the ASME Code and 10 CFR 50, Appendix B, Criterion XVI.

02.04 Steam Generator (SG) Tube Inspection Activities.

- a. In-situ Pressure Testing.
 1. **If the licensee identifies repairable indications, review the licensee's in-situ screening criteria developed for a sample of these repairable indications (suggest review of criteria applicable to indications located in the SG tube free-span or U-bend areas). Determine if the licensee's in-situ pressure test screening criteria are in accordance with the EPRI Guidelines. In particular, determine whether the assumed NDE flaw sizing accuracy is consistent with data from the EPRI examination technique specification sheet (ETSS) or other applicable performance demonstrations.**

Issue Date: 11/23/11

Effective Date: 01/01/12

2. For those tubes that satisfied the initial screening criteria for an in-situ pressure test, determine if the appropriate tubes were selected for in-situ pressure testing (in terms of specific tubes and number of tubes).
 3. (If performed) Review plans for and, if practical, observe in-situ pressure testing activities and assess whether tubes are in-situ tested in accordance with EPRI In-situ Pressure Test Guidelines. Review methods for verifying that the correct tube is in-situ tested, including positioning the test equipment at an appropriate vertical tube elevation (if a local test is performed).
 4. (If performed) Review in-situ pressure test results to determine if the tube integrity performance criteria were met. Review the in-situ pressure test records (e.g., pressure versus time traces, pressure achieved, and hold times) to determine if test was completed as planned.
- b. For a specific type of degradation (e.g. circumferential outside diameter stress corrosion cracking at the expansion transition) compare the number of tubes affected and limiting flaw sizes with that predicted by the previous outage operational assessment to assess the licensee's prediction capability.
 - c. Review the SG tube eddy current examination (ET) scope and expansion criteria to determine if these meet technical specification (TS) requirements. Further, evaluate the ET scope to determine if areas of potential degradation (based on site-specific experience and industry experience) are being inspected, especially areas which are known to represent potential ET challenges (e.g., top-of-tubesheet, tube support plates, U-bends).
 - d. If the licensee identified new degradation mechanisms, verify that the licensee's ET scope has fully enveloped the problem and that the licensee has taken appropriate corrective actions before plant startup (e.g., additional inspections, in-situ pressure testing, preventive tube plugging, etc.).
 - e. If sufficient inspection resources exist (within baseline procedure estimates), and if site or industry experience indicates a potential for secondary side internals structure degradation, review or observe secondary side examinations. Review licensee's corrective action taken in response to any observed degradation.
 - f. If the licensee repairs tubes (e.g. installs plugs or sleeves) select a sample of tube repair locations to determine if the licensee repaired the appropriate tubes. If tube repair methods other than installation of tube plugs are applied, determine if the repair processes being used have been approved by the NRC for use at the site.
 - g. Repair Criteria:
 1. Review a sample of repairable indications to determine if the TS repair criteria are being followed. Typically, the TS repair limit is 40 percent through wall, although most licensees plug (or repair) crack-like indications on detection (unless an alternate to the 40% depth based repair criteria has been approved for use). This "plug on detection" approach is due to the inability to reliably depth size crack-like indications.

2. Review a sample of repairable indications (e.g. I-Code) identified by the licensee vendor analysts to determine if the depth sizing repair criterion (typically 40 percent through wall) is being applied for indications other than wear or axial primary water stress corrosion cracking (PWSCC) at dented tube support plate intersections. If so, for these SG tubes with indications sized and returned to service, determine if the sizing method was reviewed and approved by the NRC.
- h. If steam generator leakage greater than 3 gallons per day was identified during operations or during post-shutdown, review the licensee's actions to locate the source of the leakage (e.g. secondary side pressure test, visual inspection of plugs) and determined if these actions are sufficient to identify the source of the leakage. In addition, determine whether corrective actions are planned or were taken to identify the cause of the leakage. Additional guidance on this issue is available in Part 9900: Technical Guidance, "Steam Generator Tube Primary-to-Secondary Leakage."
- i. Review a sample of the licensee's vendor and EPRI Appendices H and I (PWR Steam Generator Examination Guidelines) Examination Technique Specification Sheets to determine if the ET probes and equipment are qualified for detection or sizing of the expected types of tube degradation. In particular, focus the review on the site specific factors potentially effecting the qualification of one or more techniques (e.g., equipment, data quality/noise issues, degradation mode).
- j. If the licensee has identified loose parts or foreign material on the secondary side of the steam generator, review licensee corrective actions in conjunction with step 02.05 below. Specifically, determine if the licensee has taken/planned repairs or engineering evaluation of affected SG tubes and inspected the secondary side of the SG to remove foreign objects (if possible). If the foreign objects are inaccessible (and not removed), determine whether the licensee has performed an evaluation that considers the potential effects of object migration and/or tube fretting damage.
- k. Observe (if practical) a vendor/licensee analyst (recommend Resolution Analyst or Qualified Data Analyst) performing a review of one to five SG tubes with eddy current to determine if proper ET analysis techniques were applied. If adequate expertise for this activity does not reside in the regional office, the Office of Nuclear Reactor Regulation (NRR) should be contacted via telephone call or e-mail to discuss the need for providing this resource.

02.05 Identification and Resolution of Problems. Verify that the licensee is identifying ISI/SG problems at an appropriate threshold and entering them in the corrective action program.

71111.08-03 INSPECTION GUIDANCE

General Guidance.

For PWRs, the effort expended and the level of detail considered in performing these activities will be determined on the basis of review of the previous outage summary report, findings from the previous NRC inspection, and interaction with NRR staff. For inspection planning, determine where to place the emphasis in regard to non-SG ISI activities (Sections 02.01 through 02.03) and SG inspection activities within the estimated resources. Also, note, when applying the requirements of 02.01 through 02.03, if timing does not permit an inspection step to be performed on an activity

Issue Date: 11/23/11

Effective Date: 01/01/12

occurring in the current outage, the step may utilize the activity performed during the previous outage. In other words, these samples may be chosen from current or previous outage. Inspectors may consult the internal operating experience data base to assist in selection of risk based samples (see Inspection Manual Chapter (IMC) 2523, "NRC Application of Operating Experience in the Reactor Oversight Process" for additional guidance).

Specific Guidance.

Inspection "best practices," training material, points of contact, and selected references are located on the internal [NRC ISI Web site](#). The references and resources may be useful for inspectors; however, the information contained on this internal Web site is considered pre-decisional and use of these resources is not required for inspection activities conducted as part of this procedure.

03.01 Non-Destructive Examination (NDE) Activities and Welding Activities.

- a. Volumetric examinations provide the greatest amount of information when compared to surface and visual examinations. Review a sample of nondestructive examination (NDE) activities. The review sample should consist of two or three types of NDE activities, including at least one volumetric examination. The reviews should be of risk-significant welds or components. When performing a review or observation of the Containment General Visual Examination (Article IWE and/or IWL of Section XI), ensure that difficult to access areas (e.g. high dose areas or confined space areas such as under vessel, sumps) or areas made visible by maintenance activities (e.g. weld test channels), are included within the scope of the visual examination. Additionally, if the licensee has identified containment areas inaccessible for visual examination review the basis for this determination and if appropriate conduct a historical review of previous containment visual examination records.
- b. For non-risk based ISI programs, the required NDE method, frequency, extent and acceptance criteria are identified in Table IWX-2500-1 of the ASME Code Section XI. The specific NDE methods are further described in Section V or Section XI Appendices (I, III or VIII) of the ASME Code.
- c. For risk based ISI programs, the required NDE method, frequency, extent and acceptance criteria are identified in the licensee's Risk Based ISI program which is typically based on EPRI TR-112657 "Revised Risk-Informed Inservice Inspection Evaluation Procedure," Revision B-A (ADAMs No. ML 0134701020) with Code Case N-578-1, or Code Case N-716-1. For BWR vessel internal inspections the NDE method, frequency, extent and acceptance criteria are identified in EPRI TR-105696-R12 BWRVIP- 03 "Reactor Pressure Vessel and Internals Examination Guidelines" (ADAMs No. ML070730353).
- d. For review of NDE records with recordable relevant indications, determine if the indications were properly characterized (ASME Code Section XI, Article IWA-3300) and recorded (ASME Code Section XI, Article IWA-3200) and appropriate acceptance criteria applied (ASME Code Section XI, Article IWX-3000). If the flaw exceeds inservice acceptance criteria, determine if the flaw was appropriately analyzed and acceptable for continued service (ASME Code Section XI, Article IWX-3130).
- e. For review or observation of Section XI Code welded repairs or replacements:

1. Determine if the Weld Procedure Specification (WPS) contains the essential and supplemental essential variables (only applicable when impact tests are required by the Construction Code, e.g., ASME Code Section III or USAS B31.1) for the welding processes authorized by the WPS (ASME Code Section IX, QW-200).
2. Determine if the WPS controls essential and supplemental essential weld variables within the ranges demonstrated and qualified by the supporting Procedure Qualification Records (PQRs) (ASME Code Section IX, QW-250).
3. Observe available welding activities (or review weld records) to determine if they are performed with the appropriate base and weld filler materials and that welding variables are controlled in accordance with the WPS.
4. Review weld data records and/or observe post weld NDE to determine if the Construction Code (e.g. ASME Code Section III, Section XI or USAS B31.1) required NDE methods and acceptance criteria were applied for weld acceptance. If the inspector identifies concerns with the NDE procedures used to verify weld acceptance, confirm that these procedures are in accordance with the applicable Construction Code and ASME Code Section V requirements.

03.02 PWR Vessel Upper Head Penetration (VUHP) Inspection Activities.

As part of the preparation for vessel upper head inspection, the inspector may want to consider reviewing NRC Bulletin 2001-01, Bulletin 2002-01, Bulletin 2002-02, and NRC first revised Order EA-03-009. These documents provide the background behind 10 CFR 50.55a(g)(6)(ii)(D), and may be useful references.

03.03 Boric Acid Corrosion Control (BACC) Inspection Activities (PWRs).

As part of the preparation for inspection of boric acid corrosion control, the inspector should consider reviewing Generic Letter 88-05 and RIS 2003-13. The inspector should review licensee commitments made in response to this generic letter. The inspector can review the Boric Acid Corrosion Guidebook Revision 1 - EPRI Technical Report 1000975 to gain insights on corrosion induced wastage rates.

Licensee boric acid evaluations of configurations discussed below are suggested as a priority for review based on the higher corrosion rates possible for these configurations. The information identified below refers to tests documented in the EPRI Boric Acid Corrosion Guidebook Revision 1 - EPRI Technical Report 1000975.

- a. Vessel Head: Boric acid dripping from sources above head onto carbon steel head will cause boric acid to concentrate and corrosion rate is sensitive to the flowrate onto the heated surface (reference page 4-39 and page 4-69 for vendor tests).
- b. Heated Carbon Steel Pipe: Boric acid dripping from sources above and onto heated and insulated pipe cause boric acid to concentrate (reference page 4-47 vendor test).
- c. Boric Acid Leakage Impingement: Boric acid steam/water impingement onto bolted configurations (can be typical for pump casing joints) creates a corrosive configuration for the bolts (reference page 4-49 vendor test).

- d. Elevated Temperature Flange Leakage: Boric acid leakage (~0.1gpm) corrodes fasteners near the leak location for flanged joints operating at elevated temperature (600F) (reference page 4-78 vendor test). For lower temperatures (180F), corrosion of fasteners is much less.

03.04 Steam Generator (SG) Tube Inspection Activities.

General Guidance.

Use the factors discussed below to determine the allocation of the inspection effort for review of the licensee SG inspection activities as described in 02.04. If none of these factors apply, the minimum inspection requirement is to complete steps 02.04a., c., d., g.(1), h., i., and j. If any of the factors apply, this baseline inspection effort should include the inspection of all SG activities identified in 02.04. If the safety significance of the operating experience warrants, then consider increasing the depth of the baseline SG inspection effort beyond the maximum estimated resources if recommended by NRR/Division of Engineering (DE) and approved by NRR/DIRS/IRIB.

- SGs with Alloy 600 tubes should receive a review as described in this section at least every other outage, or more frequently if other factors discussed below apply. For SGs with Alloy 690 tubes this review may not be required unless considerable inservice time (e.g., >15 yrs since beginning commercial operation (or SG replacement, as appropriate) and more than 2 operating cycles since the last NRC inspection of the licensee's SG inspection activities) or other factors discussed below apply.
- Deteriorating SG tube material condition as evidenced by a significant increase in the number of flaws reported by the licensee during the previous SG tube examinations or an under prediction of the number or severity of flaws. This information can be obtained from the licensee's most recent SG inspection summary report and/or their operational assessment.
- SG tube performance criteria (i.e., operational leakage, structural integrity, or accident leakage) were not met during the previous operating cycle.
- PWRs with a history of primary-to-secondary leakage during the previous operating cycle (e.g., > 3 gallons per day).
- Reported potential degraded condition (e.g., NRC and industry information notices) due to SG design, water chemistry, material properties, or newly identified degradation mechanisms.

The inspection should be scheduled towards the end of the SG inspection activities, if possible, because the licensee performs a significant number of evaluations (listed in 02.04) at that time.

Attachment A lists specific situations which, if identified by the inspector, require notification of NRR staff. In addition, the inspector is encouraged to contact NRR staff to discuss any other situations or issues that are identified, that are unexpected based on the inspector's experience.

Prior to an inspection, and as a part of the preparation for SG tube inspections, the inspector should contact NRR staff to determine the existence of issues or concerns that should be considered for review during the SG tube inspection. The inspector should also consider reviewing the licensee's commitments in response to Generic

Issue Date: 11/23/11

Effective Date: 01/01/12

Letters (GLs) 97-05, and 97-06 (see References Section 06). In addition, the inspector should review the licensee's most recent SG inspection summary report. The inspector should also consider reviewing NRC generic communications, such as relevant information notices and regulatory information summaries. Lastly, the inspector should become familiar with the industry steam generator program contained in Nuclear Energy Institute (NEI) 97-06 and several related Electric Power Research Institute (EPRI) reports (see References Section 06). The EPRI guidelines referenced **may not constitute NRC requirements or commitments (depending on the plant-specific details of the licensee's SG Program)** and technically acceptable alternative methods may be used by the licensee. **If the licensee has deviated from the EPRI guidelines, the basis for the deviation should be documented by the licensee.** Although the guidelines represent an improvement over practices followed in the past, use of the guidelines alone **may not ensure that the regulations will be satisfied.**

Periodically, for plants that have SGs with active degradation or other SG issues, NRR/DE staff will conduct a conference call with the licensee to discuss SG tube examination activities. If scheduled by NRR/DE, the inspector should participate in the conference calls set up between NRC and licensee staff (as the timing of the call permits), during which steam generator tube examination activities are discussed. In addition, the inspector should review summaries from previous similar conference calls and can obtain these from NRR/DE staff. The information obtained during these calls will be beneficial to the inspector for background information as well as potentially providing direction for inspection activities.

Specific Guidance.

- a. In-Situ Pressure Testing
 1. The inspector should review the EPRI Guidelines for in-situ screening criteria in order to determine if the licensee's criteria meets that guidance.
 2. The inspector should review test data to determine if the appropriate tube(s) has/have been properly identified for in-situ pressure testing.
 3. The inspector should observe, when possible, the in-situ testing. The inspector should review the test procedure. The inspector should determine that the test was performed in accordance with the procedure and the EPRI In-Situ Pressure Test Guidelines.
 4. The inspector should evaluate the results of the test against the performance criteria identified in the test procedure.
- b. The inspector should review the results of the current examinations to determine the ability of the licensee to predict future tube performance through assessment of previous performance.
- c. The inspector should review the licensee's examination scope and expansion criteria to determine if both meet the technical specification requirements, commitments made to the NRC, and the EPRI Guidelines. **Compare the licensee's SG tube inspection plan scope to the previous outage summary report and NRR identified industry issues to verify that all areas of potential degradation have been included.**
- d. New degradation mechanisms are identified by the licensee based on a comparison of the summary report of the previous outage results to the current outage results. The inspector should notify NRR of the new mechanism. NRR

will assist in evaluation of the corrective actions. If the steam generators have been replaced, then the first subsequent outage examination results should be compared to the PSI data. (Wear indications observed during the first inspection following steam generator replacement should not be considered a new degradation mechanism unless a large number of indications (greater than approximately 100 indications per steam generator) are detected or if large through wall extents are observed (greater than 30% through-wall).)

- e. Confirm that the secondary side inspections are being conducted in accordance with the licensee's governing documents (e.g. Steam Generator Management Program: Steam Generator Integrity Assessment Guidelines, Part 10).
- f. If the licensee repairs tubes (e.g. installs plugs or sleeves) select a sample of tube repair locations to determine if the licensee installed repairs at the appropriate tube locations. This can be accomplished by direct observation or review of licensee quality control measures implemented to ensure the correct tube is located for repairs. Typically, two independent means (repair robot encoder positions, manually counting tube rows or columns and machine vision systems) are used to locate tubes. If tube repair methods (other than installation of tube plugs) are applied, review the applicable docketed site correspondence to determine if the repair processes being used were approved by the NRC and were implemented consistent with the approved process.
- g. Confirm, in the absence of "plug on detection," that the licensee has depth sizing techniques that provide reasonable estimates of the depth of degradation such that the typical TS repair limit of 40 percent through-wall can be implemented without a loss of tube integrity for the period of time between inspections.

This criteria may be acceptable and in accordance with the licensee's TS, although experience has shown, for example, that many types of IGA/SCC cannot be sized with a sufficient degree of accuracy or reliability. In addition, this may indicate licensee practices that are inconsistent with their response to GL 97-05. If that is the case, contact NRR.

- h. It is suggested that the NRC resident inspectors and regional staff use an informal screening criteria of 3 gpd or greater for increased involvement by NRC headquarters staff when steam generator primary to secondary leakage is identified. This is not meant to be an absolute threshold, or requirement, because there may be certain instances where there is something unusual about the circumstances of the leakage, or other reason that the region would want involvement by the headquarters staff before leakage reaches 3 gpd. If a licensee reports levels of primary-to-secondary leakage exceeding 3 gpd to the resident inspector or regional staff, Office of Nuclear Reactor Regulation (NRR) should be informed through the morning phone calls. The following section discusses some of the typical questions that inspectors can pursue with the licensee when leakage is reported.

When leakage exceeds 3 gpd, parameters that can be considered are the effectiveness of licensee procedures, equipment, and practices for monitoring and responding to primary-to-secondary leakage. For example, the adequacy of procedures and equipment to provide real-time information on leak rate and its rate of change could be assessed. The appropriate setting of alarm setpoints on those radiation monitors that are used for detecting primary-to-secondary leakage (e.g., condenser air ejector, N-16) to alert operators to any increasing leak rate could be assessed. In addition, the adequacy of emergency operating

procedures, availability of systems and components, and operator training for response to steam generator tube ruptures could also be assessed.

The NRR staff often receives notification of extremely low levels of leakage (< 1 gpd), but these levels of leakage don't typically need to result in increased interaction with the licensee. This is because many plants have experienced this level of leakage during a full cycle, and it's difficult to definitively determine the source of the leakage at that level. Often, small levels of leakage will persist for the rest of the operating cycle for some plants.

- i. Review the equipment and probes used for the examination(s). For example, review the test configuration (i.e., frequency, coil selection, probe drive, and physical limitations). Verify that the appropriate ET probe (e.g., bobbin, pancake, or multi-coil type) is used to detect the type of flaw that might be expected. Verify that the equipment has been calibrated in accordance with the ET procedure(s) and ASME Code.
- j. No specific guidance.
- k. No specific guidance.

03.05 Identification and Resolution of Problems.

For a selected sample of problems associated with inservice inspection and steam generator inspection documented by the licensee, verify the appropriateness of the corrective actions. See IP 71152, "Identification and Resolution of Problems," for additional guidance. In addition, a licensee's evaluation of industry operating experience can be critical. Determine whether licensees are assessing the applicability of operating experience to their respective plants.

71111.08-04 RESOURCE ESTIMATE

This IP is estimated to take 30 to 42 hours for each BWR unit, and 80 to 100 hours for each PWR unit, every refueling outage.

Depending on availability, resident staff members may assist the regional ISI inspectors in completing section 02.03, Boric Acid Corrosion Control (BACC) Inspection Activities (PWRs).

71111.08-05 COMPLETION STATUS

This IP is required to be performed each refueling outage. Inspection of the minimum sample size will constitute completion of this procedure in the Reactor Program System (RPS).

The minimum sample size for each BWR unit is 1 sample, and consists of all the requirements (if available) in section 02.01.

The minimum sample size for each PWR unit is 1 sample, and consists of all the requirements (if available) in section 02.01, 02.02, 02.03, and 02.04.

If a particular activity is not completed because the licensee was not scheduled to perform this activity in the refuel outage, then document this in the inspection report; however the sample should be reported as complete in RPS. For example section

Issue Date: 11/23/11

Effective Date: 01/01/12

02.04 specifies many activities. If one activity is not completed in section 02.04 because it is not available, the sample should still be documented as complete.

71111.08-06 REFERENCES

Reference documents should be verified to be the current revision prior to use. Most reference documents can be obtained through the Electronic Reading Room on the NRC public website (www.nrc.gov).

10 CFR 50.55a(g)(6)(ii)(D)

ASME Boiler and Pressure Vessel Code Sections III, V, IX, and XI

Plant-specific ISI program

GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants"

GL 97-05, "Steam Generator Tube Inspection Techniques"

GL 97-06, "Degradation of steam Generator Internals"

GL 2004-01, "Requirements for Steam Generator Tube Inspections"

GL 2006-01, "Steam Generator Tube Integrity and Associated Technical Specifications"

NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Pressure Boundary Integrity"

NRC Bulletin 2003-02, "Leakage From Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity"

NRC Regulatory Issue Summary (RIS) 2003-13, "NRC Review of Responses to Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity"

NRC RIS 2007-20, Implementation Of Primary-To- Secondary Leakage Performance Criteria

NRC RIS 2009-04, "Steam Generator Tube Inspection Requirements"

NRC Information Notice 2010-05, "Management of Steam Generator Loose Parts and Automated Eddy Current Data Analysis"

NEI 97-06, "Steam Generator Program Guidelines." (Agencywide Documents Access and Management System (ADAMS) Accession No. ML052710007)

EPRI PWR Steam Generator Examination Guidelines (ADAMS Accession No. ML062360553)

EPRI Steam Generator Integrity Assessment Guidelines (ADAMS Accession No. ML100480264)

EPRI Steam Generator In Situ Pressure Test Guidelines (ADAMS Accession No. ML072970252)

Issue Date: 11/23/11

Effective Date: 01/01/12

EPRI Primary-to-Secondary Leak Guidelines (ADAMS Accession No. ML050840522)

EPRI Primary Water Chemistry Guidelines (ADAMS Accession No. ML081140284)

EPRI Secondary Water Chemistry Guidelines (ADAMS Accession No. ML050840514)

IMC 2523, "NRC Application of Operating Experience in the Reactor Oversight Process"

IP 71152, "Identification and Resolution of Problems"

IP 71111.20, "Refueling and Other Outage Activities"

Part 9900: Technical Guidance, "Steam Generator Tube Primary-to-Secondary Leakage"

First Revised Order, EA-03-009, "Issuance of Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," February 20, 2004

WCAP-15988-NP, "Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors," Revision 1 April 2005 (ADAMS Accession No. ML050960532).

END

APPENDIX A

Tube Integrity Issues Requiring Further Evaluation by NRR Staff

If the following situations are identified by the inspector, NRR/DE staff should be promptly contacted. NRR/DE staff will determine whether NRR involvement is necessary. In addition, the inspector is encouraged to contact NRR/DE staff to discuss any other situations or issues that are identified, that are unexpected based on the inspector's experience.

1. Selection of tubes to be in-situ pressure tested is not consistent with EPRI guidance (i.e., number of tubes to be tested, or specific tubes to be tested, or NDE uncertainty is not consistent with data from the EPRI examination technique specification sheet (ETSS) or other applicable performance demonstrations).
2. In-situ pressure testing of flawed tubes is not successful in reaching the desired test pressure (e.g., main steam line break for accident induced leakage, 3 times normal operating differential pressure and 1.4 times main steam line break pressure for burst), either due to tube failure/leakage or equipment problems/limitations.
3. Estimated size or number of tube flaws detected during the current outage invalidates bounding assumptions from the previous outage operational assessment predictions.
4. If the licensee's use of depth sizing is inconsistent with their response to NRC Generic Letter 97-05.
5. A tube repair criteria or repair process is being used which has not been reviewed by the NRC for use at this site (e.g., alternate tube repair criteria, or sleeving process).
6. If inspections or testing do not identify the source of primary-to-secondary leakage observed during the previous operating cycle or during **plant shutdown**.
7. **If new SG tube degradation mechanisms are identified by the licensee.**
8. **If a licensee reports levels of primary-to-secondary SG tube leakage exceeding 3 gpd.**
9. **If adequate expertise does not reside in the Regional Office for review of eddy current indications data to determine if proper ET analysis techniques were applied.**

ATTACHMENT 1
 REVISION HISTORY FOR IP 71111.08

Commitment Tracking Number	Issue Date	Description of Change	Training Needed	Training Completion Date	Comment Resolution Accession Number
C-1 Reference: DBLLTF 3.3.4(3)		Revision History Reviewed for last four years. Develop Inspection Guidance for Vessel Head Penetrations and RPV Head Area Inspections.	No	N/A	N/A
C-2 Reference: DBLLTF 3.3.2(1)		Revision history reviewed for last four years. Develop Inspection Guidance For Boric Acid Corrosion Control Programs.	No	N/A	N/A
None	10/04/07 CN 07-031	IP 71111.08 has been revised to incorporate best practices of ISI working group.	No	N/A	ML072400349
None	03/23/09 CN 09-010	IP 71111.08 has been revised to address feedback form 71111.08-1319 by incorporating the changes to 10 CFR 50.55a(g)(6)(ii)(D)	No	N/A	N/A

None	11/09/09 CN 09-026	IP 71111.08 has been revised based on the 2009 ROP Realignment (added 12 hours to the resource estimate for BWR inspections) and to address feedback form 71111.08-1373 (editorial corrections) and 71111.08-1386 (clarification of sample requirements).	No	N/A	N/A
None	ML11262A023 11/23/11 CN 11-038	IP 71111.08 has been revised to as part of a 2011 ISI working group effort to incorporate best practices.	No	N/A	N/A