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August 17, 2009

United States Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Serial No.: 09-469
LR/MWH R2
Docket No.: 50-305
License No.: DPR-43

DOMINION ENERGY KEWAUNEE, INC.
KEWAUNEE POWER STATION
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE KEWAUNEE POWER STATION LICENSE RENEWAL APPLICATION – AGING MANAGEMENT PROGRAMS

By letter dated July 13, 2009 (Reference 1), the NRC requested additional information regarding the aging management programs and metal fatigue time-limited aging analyses (TLAA) included in the license renewal application (LRA) for Kewaunee Power Station (KPS) (Reference 2). The NRC staff indicated that the responses to the requests for additional information (RAIs) are needed to complete the review related to the KPS LRA. The attachment to this letter contains the responses to the RAIs.

Should you have any questions regarding this submittal, please contact Mr. Paul C. Aitken at (804) 273-2818.

Very truly yours,

Stephen E. Scace
Kewaunee Power Station Site Vice President

STATE OF WISCONSIN)
)
COUNTY OF KEWAUNEE)

The foregoing document was acknowledged before me, in and for the County and State aforesaid, today by Stephen E. Scace, who is Kewaunee Power Station Site Vice President of Dominion Energy Kewaunee, Inc. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of that Company, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 17th day of August, 2009.

My Commission Expires: March 28, 2010

Jeannie C. Miller
Notary Public

A135
NRR

References:

1. Letter from Samuel Hernandez (NRC) to David A. Heacock (DEK), "Request for Additional Information for the Review of the Kewaunee Power Station License Renewal Application – Aging Management Programs (TAC No. MD9408)," dated July 13, 2009. [ADAMS Accession No. ML091810958]

2. Letter from D. A. Christian (DEK) to NRC, "Kewaunee Power Station Application for Renewed Operating License," dated August 12, 2008. [ADAMS Accession No. ML082341020]

Attachment:

1. Response to Request for Additional Information for The Review of the Kewaunee Power Station License Renewal Application – Aging Management Programs

Commitments made in this letter:

1. Additional information will be included in the USAR Supplement (LRA Appendix A), including License Renewal Commitments identified in Table A6.0-1, as applicable. These USAR Supplement changes will be consistent with the responses to RAIs B2.1.13-5, B2.1.14-3, B2.1.15-1, B2.1.18-1, B2.1.21-1, B.2.1.31-1, and B3.1-1, are proposed to support approval of the renewed operating license, and may change during the NRC review period.

2. The response to RAI B3.2-2 will be provided following re-evaluation of the environmental effects of fatigue for the NUREG/CR-6260-required evaluations that used stress-based fatigue monitoring.

cc:

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Serial No. 09-469
Docket No. 50-305

ATTACHMENT 1

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE KEWAUNEE POWER STATION LICENSE RENEWAL APPLICATION – AGING MANAGEMENT PROGRAMS

KEWAUNEE POWER STATION
DOMINION ENERGY KEWAUNEE, INC.

License Renewal Application (LRA) Aging Management Program (AMP) B2.1.2

American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Request for Additional Information (RAI) B2.1.2-1

Background

NUREG-1801, Generic Aging Lessons Learned (GALL) Report, recommends a stand-alone program to address aging management of class 1 small bore piping up to NPS 4". The program is specified in GALL Report AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small Bore Piping." The applicant does not have a program consistent with GALL AMP XI.M35, but chooses instead to use AMP B2.1.2, "ASME Section XI, Inservice Inspection – IWB, IWC, and IWD" to cover small bore piping aging management program.

Issue

AMP B2.1.2 does not fully address issues as recommended in GALL Report AMP XI.M35.

Request

Please provide program information on aging management of class 1 small bore piping up to NPS 4".

DEK Response

ASME Class 1 small-bore piping is managed by the ASME Section XI Inservice Inspections Subsections IWB, IWC and IWD program (ISI Program) described in LRA Appendix B, Section B2.1.2. Kewaunee is in the fourth 10-year inservice inspection interval, which began on June 16, 2004 and will end on June 16, 2014. For the fourth 10-year inservice inspection interval, the NRC approved the Risk Informed - Inservice Inspections (RI-ISI) submittal as an alternative to ASME Section XI in a letter from NRC to NMC dated September 23, 2005 [ADAMS ML052660057].

Consistent with NUREG-1801, Section XI.M35, "One-Time Inspection of ASME Code Class 1 Small Bore Piping," the RI-ISI program selects examination locations of ASME Class 1 small-bore piping welds based on risk significance and the potential for presence of aging mechanisms including cracking. The sample size is based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small-bore piping locations.

The currently approved ISI Program performs the following examinations for small-bore piping welds:

1. Examination Category B-J, Item No. B9.21, 96 ASME Class 1 circumferential welds and 8 ASME Class 1 small-bore circumferential welds are scheduled to receive volumetric and surface examinations during the fourth 10-year interval. Four of these small-bore welds have received a volumetric and surface examination to date and no ASME Class 1 small-bore circumferential weld cracking has been identified.
2. Examination Category B-J, Item No. B9.40, 320 ASME Class 1 socket welds and 20 small-bore ASME Class 1 socket welds are scheduled to receive surface examinations during the fourth 10-year interval. Twelve of these small-bore welds have received a surface examination to date and no ASME Class 1 small-bore socket weld cracking has been identified.
3. Visual inspections (VT-2 inspections) of all ASME Class 1 small-bore piping at operating pressure during each refueling outage.

The ISI Program will continue to be performed through the period of extended operation and provides acceptable management of aging effects for ASME Class 1 small-bore piping by continued monitoring for weld cracking.

RAI B2.1.2-2

Background

GALL Report AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small Bore Piping," recommends one time volumetric inspection of small bore piping.

Issue

No specific information was provided regarding examination of small-bore piping socket welds. During an onsite audit discussion, the applicant indicated that there are 450 class 1 welds up to NPS 4", some of which are sockets welds.

Request

Please provide information on the examination of small bore piping socket welds.

DEK Response

A discussion of the application of ASME Section XI, "Inservice Inspections," Subsections IWB, IWC and IWD program (ISI Program) to small bore piping is provided in the response to RAI B2.1.2-1. For Examination Category B-J, Item No. B9.40, there are 320 ASME Class 1 socket welds. During the fourth (current) 10-year inspection interval, the Risk Informed - Inservice Inspection Program selected 20 small-bore ASME Class 1 socket welds to receive surface examinations, based on risk significance and the potential for aging mechanisms. Twelve of the 20 examinations have been completed to-date and there have been no indications of cracking. Additionally, visual inspections of the ASME Class 1 piping systems at nominal operating pressure are performed during each refueling outage.

The surface examination of select small bore socket welds and the visual inspection of the ASME Class 1 piping systems are consistent with the requirements of ASME Section XI.

There is no industry demonstrated means of performing volumetric examinations to detect cracking initiating at the inside diameter of a socket weld. The issue of performance of volumetric examination on ASME Class 1 socket welds was resolved and included in the NRC summary of the License Renewal telephone conference call and meeting between the NRC staff and the NEI License Renewal Task Force held on February 21, 2007 (Summary of the License Renewal Telephone Conference Call and Meeting Held Between the U.S. Nuclear Regulatory Commission Staff and the Nuclear Energy Institute License Renewal Task Force, dated March 6, 2007, ADAMS Accession No. ML070580498). The NRC concluded that additional socket weld examinations beyond the current ASME code requirements will not be required for license renewal.

The examinations performed in accordance with the ISI Program for small bore socket welds are consistent with the NRC summary of the telephone conference call discussed above. These examinations have been found to be acceptable for management of aging in small bore ASME Class 1 piping in previous license renewal reviews as documented in the Safety Evaluation Report Related to the License Renewal of Beaver Valley Power Station, Units 1 and 2, (letter from NRC to First Energy Nuclear Operating Company, dated June 8, 2009, ADAMS Accession No. ML091600216) and the NUREG-1920, "*Safety Evaluation Report Related to the License Renewal of Vogtle Electric Generating Plant, Units 1 and 2.*"

LRA AMP B2.1.3

ASME Section XI, Subsection IWE

RAI B2.1.3-1

Background

Indications of reactor refueling cavity leakage have been documented during Kewaunee Power Station (KPS) refueling outages.

Issue

Refueling cavity leakage could contact the containment vessel and cause degradation of inaccessible regions of the vessel, specifically the areas that are surrounded by concrete.

Request

Explain how the IWE program is addressing this possible aging effect, or why it is not necessary to evaluate it under the IWE program.

DEK Response

The scope of the IWE program is associated with the metal pressure retaining boundary of the reactor containment vessel. Moisture barriers that prevent intrusion of moisture into inaccessible areas of the containment shell at concrete-to-metal interfaces are also inspected as part of the IWE program. If moisture barrier degradation is observed, the condition is documented in the Corrective Action Program. The Corrective Action Program will evaluate the apparent cause and determine required corrective actions.

In the fall of 2006 and again in 2008, during inspections performed under the Boric Acid Corrosion Program and the Structures Monitoring Program, the reactor cavity/refueling pool was identified as a potential source of leakage. The area below the reactor cavity and the A-RCS loop vault were identified as the two most likely locations and the extent of the leakage was evaluated. The amount of leakage was categorized as minimal (streaking of the walls). The leakage was determined to not have come into contact with the reactor containment vessel. Therefore, the reactor containment vessel was not required to be evaluated for this identified leakage by the IWE program.

Condition reports were entered into the Corrective Action Program to address the identified leakage conditions.

RAI B2.1.3-2

Background

ASME Section XI, Subsection IWE-1241 discusses surfaces requiring augmented examinations, including "interior and exterior containment surface areas that are subject to accelerated corrosion with no or minimal corrosion allowance." Such areas may include surfaces that are wetted during refueling, concrete-to-steel shell interfaces, embedment zones and sump liners.

Issue

KPS may have containment locations that require augmented examinations based on the above description, specifically at concrete-to-steel interfaces and embedment zones.

Request

Please provide the minimum required containment vessel design thickness, the nominal containment vessel thickness, and any locations that require augmented examinations based on the requirements of IWE-1241. Provide the results of any required augmented examinations.

DEK Response

The Reactor Containment Vessel minimum required design thickness and nominal thickness are the same value. The nominal thickness of the Reactor Containment Vessel shell and ellipsoidal bottom is 1-1/2 inch and the nominal thickness of the Reactor Containment Vessel hemispherical dome is 3/4 inch. Per the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWE, Article IWE-3511.3, examinations of pressure retaining components that detect material loss in a local area exceeding 10% of the nominal wall thickness shall be documented. Additionally, such local areas shall be accepted by engineering evaluation or corrected by repair/replacement activities.

Currently, there are no Reactor Containment Vessel surface areas that are experiencing accelerated degradation, which would require augmented examinations based on the requirements of IWE-1241.

RAI B2.1.3-3

<u>*Background*</u>

The GALL Report includes AMP XI.S8, "Protective Coating Monitoring and Maintenance" to ensure proper maintenance of protective coatings inside containment. In the KPS LRA, the ASME Section XI, Subsection IWE AMP mentions coating degradation under operating experience however, the LRA does not include aging management of coatings.

<u>*Issue*</u>

The failure of coatings could result in aging effects for the steel containment vessel, as well as failure of safety systems to perform their intended functions.

<u>*Request*</u>

Please justify not having an aging management program for coatings, including a discussion of plant-specific operating experience relating to coating inspections and degradation.

DEK Response

As indicated in LRA Section 2.4.1, protective coatings are not relied upon to manage the effects of aging of the Reactor Containment Vessel. Coatings provide protection for the underlying base metal but do not perform an intended function as defined in 10 CFR 54.4(a)(1), (2) and (3).

The ASME Section XI, Subsection IWE program manages the aging effect of loss of material due to corrosion for the Reactor Containment Vessel. The program inspects for evidence of corrosion and utilizes the condition of the coated surface as a means to evaluate the condition of the underlying base metal. Specifically, the program visually inspects for evidence of flaking, blistering, peeling, discoloration, corrosion, and other signs of distress. Areas showing evidence of corrosion are required to be accepted by engineering evaluation or corrected by repair or replacement.

The benefits of the protective coating on the Reactor Containment Vessel are recognized and proper maintenance of the protective coatings is being addressed by the action plan developed in response to Generic Letter 2004-02, "*Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors,*" and Generic Letter 98-04, "*Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-Of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material In Containment.*" The Generic Letter requirements related to aging management will become part of the Current Licensing Basis and therefore, will carry forward into the period of extended operation.

LRA AMP B2.1.4

ASME Section XI, Subsection IWF

RAI B2.1.4-1

Background

ASME Section XI, Subsection IWF-2430 requires additional examinations when conditions are revealed that exceed the acceptance standards of IWF-3400.

Issue

During the AMP audit, the staff reviewed KPS surveillance procedure SP-55-085, which states "additional examinations for support and hanger visual indications that exceed acceptance standards of ASME Boiler and Pressure Vessel Code will be addressed by the Kewaunee Power Station Augmented Program for Class 1, Class 2, and Class 3 Supports and Hangers." No discussion is provided on how this program, or the additional ASME examinations, are implemented. In addition, attachments seven and eight of KPS procedure ER-AA-NDE-VT-603 used for documenting the visual examination of supports does not include guidance for initiating additional examinations to comply with IWF-2430.

Request

Please explain how the requirements of IWF-2430 are satisfied. If the augmented IWF program is credited for the additional examinations, explain how the augmented program is implemented and how it satisfies the requirements of IWF-2430.

DEK Response

ASME Section XI, Table IWF-2500-1 requires 25% of Class 1 piping supports, 15% of Class 2 piping supports, and 10% of Class 3 piping supports to be examined over each inspection interval (i.e., every 10 years) using the VT-3 examination method. The minimum number of examinations and examination technique required by ASME Section XI are satisfied by the completion of Surveillance Procedure SP-55-085, "Ten Year Inservice Inspection Requirements."

For convenience, Surveillance Procedure SP-55-085 examines essentially 100 percent of all required accessible supports and hangers over the ten-year interval. The expanded number of examinations is accomplished by performing examinations of all the accessible supports in an area at one time using the same standards and techniques required by ASME Section XI. This practice can provide the opportunity to envelope any additional examinations that may be required by IWF-2430 (a), (b), (c), and (d). In the event additional examinations are required based on a valid indication, Surveillance Procedure SP-55-085 may have already performed the additional required examinations without having to re-enter an area.

The augmented program is comprised of the routine additional examinations described above, which exceed the minimum number of examinations required by Table IWF-2500-1, and any additional examinations required by IWF-2430 (a), (b), (c), and (d) that were not encompassed by the routine additional examinations. When the routine additional examinations do not encompass the additional examinations required by IWF-2430 (a), (b), (c), and (d), additional examinations are incorporated into the program using Nuclear Fleet Administrative Procedure ER-AA-ISI-100, "Dominion Inservice Inspection Program." Administrative Procedure ER-AA-ISI-100 directs personnel to update the ISI Program, in accordance with Nuclear Fleet Administrative Procedure ER-AA-ISI-101, "Dominion Inservice Inspection Program Preparation and Change Control Process."

The requirements of IWF-2430 always control the additional examinations performed regardless of the supports that Surveillance Procedure SP-55-085 may or may not have already examined. The augmented program does not supersede or modify the requirements to determine and perform additional examinations of supports required to satisfy ASME Boiler and Pressure Vessel Code Section XI IWF-2430 (a), (b), (c), and (d).

LRA AMP B2.1.5, Bolting Integrity

RAI B2.1.5-1

Background

In the KPS LRA, the B2.1.5 "Bolting Integrity Program" Item 4.2 states that the program implements recommendations and guidelines in EPRI NP-5769 section 1 and volume 2, and NUREG-1339 for a comprehensive bolting integrity program, is to include training of plant staff with respect to bolting Issues. However, the program does not specify the frequency of training for bolting issues.

Issue

In order to assure proper training of bolting procedures it is important to not only have a training program, but one of structured frequency to assure that all staff personnel pertinent to the program receive proper training in acceptable intervals and frequency.

Request

Please state the various bolting integrity training programs and the frequency of this training for applicable staff personnel.

DEK Response

Mechanical maintenance personnel are responsible for proper assembly/disassembly of bolted joints or connections, including those involving the system pressure boundary. Mechanical maintenance personnel, as part of initial qualification training, receive specific instruction on proper bolting techniques.

Mechanical maintenance continuing training is conducted quarterly throughout the year. Mechanical maintenance personnel are provided with continuing training on mechanical plant components such as heat exchangers, valves, pumps, piping systems, etc., in which proper bolting techniques are reinforced. Specific bolting refresher training may be requested by maintenance department supervision and/or the training review board for identified performance deficiencies noted through either job observations or adverse Corrective Action Program trends.

Engineering personnel may be involved with bolting issues such as joint design, or material, gasket, and lubricant selection. The implementation of Enhancement 1 to the Bolting Integrity Program described in LRA Appendix B, Section B2.1.5, is anticipated to result in increased knowledge for plant personnel, including engineering support personnel, related to general bolting industry operating experience and bolting fundamentals.

RAI B2.1.5-2

Background

In the KPS LRA, the B2.1.5 "Bolting Integrity Program" Item 4.6 states that ASME pressure retaining bolting and nuclear steam supply system (NSSS) component support bolting indications are evaluated in accordance with Section XI of the ASME Code. The section goes on to state that particular subsections pertinent are IWB, IWC, and IWD.

Issue

Subsections IWB, IWC, and IWD are still too vague and need specific section numbers that are relevant so they can be referenced and verified properly and quickly.

Request

Please provide the relative section numbers.

DEK Response

LRA Appendix B, Section B2.1.5 states that additional inspections of installed bolting within the scope of the Bolting Integrity Program are performed by other aging management programs including the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program and the ASME Section XI, Subsection IWF Program.

The Inservice Inspection (ISI) Program is performed to the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, 1998 Edition, 2000 Addenda for Class 1, Class 2, and Class 3 components and component supports. ASME Section XI, Subsections IWB, IWC, IWD, and IWF all contain Subarticle IWx-2500, "Examination (and Pressure Test) Requirements," which indicates that components shall be examined as specified in Table IWx-2500-1. Table IWx-2500-1 identifies the "Acceptance Standard" articles, along with other requirements for the particular parts examined.

RAI B2.1.5-3

Background

Section 5.1 of the LRA's AMP: Enhancement I: Bolting Program Improvements states that the Bolting Integrity Program will be enhanced to further incorporate applicable electric power research institute (EPRI) documents and industry bolting guidance pertinent to joint assembly, torque, values, gasket types, lubricants, and other bolting fundamentals. However, the section does not state which EPRI documents covers these items.

Issue

Specific EPRI documents needs to be stated.

Request

Provide the specific applicable EPRI documents credited in this AMP. For instance, EPRI 1015336, and EPRI 1015337.

DEK Response

The enhancement to the Bolting Integrity Program will include applicable information contained in the following EPRI bolting guidance documents:

- EPRI NP-5067, "Good Bolting Practices – Volume 1, Large Bolt Manual."
- EPRI NP-5067, "Good Bolting Practices – Volume 2, Small Bolts and Threaded Fasteners."
- EPRI TR-104213, "Bolted Joint Maintenance and Application Guide."
- EPRI 1015336, "Bolted Joint Fundamentals."
- EPRI 1015337, "Assembling Gasketed, Flanged Bolted Joints."

RAI B2.1.5-4

Background

In the KPS LRA, the B2.1.5 "Bolting Integrity" AMP is stated to be consistent, with enhancement, with the GALL report XI.M18, "Bolting Integrity" AMP. However, the LRA is not clear in how it satisfies the GALL report program element, "parameters monitored/inspected" regarding the monitoring of high strength bolts for cracking. In addition, LRA Section 3.3.2.2.4.4 states that stress corrosion cracking does not apply since high strength bolts do not exist in the specific system.

Issue

KPS LRA Section 3.3.2.2.4.4, states that the bolting associated with the high-pressure charging pump pressure head are not fabricated from high-strength steel, and concludes that therefore, this item is not applicable. However, the staff found in accordance to documentation provided by the applicant on-site, which contains the system specific to the NSSS, there exists high strength bolts (yield strength >150 ksi) that are being used in the NSSS supports associated with the reactor coolant pumps and the steam generators. The applicant's basis document states that a detailed review of the application and installation of high strength bolting has led to the assessment that stress-corrosion cracking (SCC) is an aging effect that does not require specific aging management. The applicant then concludes that this bolting unique to the NSSS support stand will be managed only for the loss of material aging effect, and not for cracking. The staff noted that if these steel bolts specific to the NSSS supports are fabricated from high strength bolting materials, then the applicant must justify why they have assessed that the SCC aging effect does not require specific aging management beyond the loss of material aging effect and also identify this as an exception to the GALL report XI.M18 "Bolting Integrity" AMP.

Request

- *Please provide further justification and analyses on the applicability of cracking in high strength bolts as it relates to LRA section 3.3.2.2.4.4.*
- *Furthermore, please identify why this item is not an exception to the GALL report XI.M18 "Bolting Integrity" AMP, even though cracking is not identified as an aging effect for high strength bolts by KPS; contrary to the recommendations in GALL report program element, "parameters monitored/inspected."*

DEK Response

As indicated in NUREG-1801, "*Generic Aging Lessons Learned (GALL) Report*," Volume 1, Table 3, Row ID 10, the recommendation for further evaluation of cracking of high-strength steel closure bolting for Item 3.3.1-10 in LRA Table 3.3.1 only applies to Chemical and Volume Control System (CVCS) high-pressure pump closure bolting (i.e., NUREG-1801 Unique Item VII.E1-8). Therefore, LRA Section 3.3.2.2.4.4 only addresses CVCS high-pressure pump closure bolting. As correctly stated in LRA Table 3.3.1, Item 10, the bolting associated with the high-pressure charging pumps pressure head at Kewaunee are not fabricated from high-strength steel, therefore, stress corrosion cracking is not an aging effect requiring management.

With respect to high-strength bolts (yield strength >150 ksi) used in the NSSS supports associated with the reactor coolant pumps and the steam generators, stress corrosion cracking is not an aging effect requiring management. Stress-corrosion cracking (SCC) is an aging mechanism that requires the simultaneous action of a corrosive environment, sustained tensile stress, and a susceptible material. Elimination of any one of these elements will eliminate the susceptibility to SCC.

For the reactor coolant pumps, Table 3.5.2-15, footnote 1, indicates that the connecting bolts to the reactor coolant pumps are high strength steel that are only hand tightened at each end and therefore, do not have the tensile stress required for stress corrosion cracking. For the steam generators, Table 3.5.2-15, footnote 4, indicates that the footbolts of the steam generator are high strength stainless steel bolts that inherently have good resistance to stress corrosion cracking, are not subjected to a corrosive environment and have relatively low tensile stresses. Based on this information, the aging management review for the steam generator concluded that the stainless bolts are not subject to stress corrosion cracking. Therefore, based on the above discussion, cracking due to SCC is not an aging effect requiring management for these NSSS high strength support bolts.

LRA Table 3.5.2-15 indicates that the connecting bolts to the reactor coolant pumps are high strength steel that require aging management for loss of material/general corrosion and specifies the Bolting Integrity Program to manage this aging effect. Therefore, since NUREG-1801, Section XI.M18, "Bolting Integrity," identifies loss of material as a "Parameter Monitored/Inspected," this is not an exception.

LRA AMP B2.1.7, Buried Piping and Tanks Inspection

RAI B2.1.7-1

<u>Background</u>

The applicant states that its proposed aging management program Buried Piping and Tanks Inspection (B2.1.7) (LRA AMP) is consistent with the aging management program Buried Piping and Tanks Inspection (XI.M34) contained in the GALL Report (GALL AMP). Section 1 (Scope of Program) of the GALL AMP includes buried steel piping and tanks. The LRA AMP includes steel and stainless steel piping and tanks. According to chapter IX.C of Volume 2 of the GALL Report, stainless steel is not included in the definition of steel.

<u>Issue</u>

The LRA AMP includes stainless steel piping while the GALL AMP does not. The proposed AMP also indicates that the stainless steel piping is coated and/or wrapped. Wrapping stainless steel piping could be harmful to its corrosion resistance.

<u>Request</u>

Please revise the LRA AMP to reflect that the inclusion of stainless steel is an exception to the GALL AMP. Please clarify whether the stainless steel piping is coated.

DEK Response

The LRA is supplemented to replace the following wording in LRA Appendix B, Section B2.1.7, Exceptions to NUREG-1801:

> The Buried Piping and Tanks Inspection Program takes no exceptions to the recommendations of NUREG-1801, Section XI.M34, 'Buried Piping and Tanks Inspection.'

The above wording will be replaced with the following:

> **Exception 1:** Use of a Material Not in the NUREG-1801, Section XI.M34 Program
>
> The program manages the aging of stainless steel piping though the NUREG-1801, Section XI.M34 program. However, this program only includes steel as a managed material.
>
> **Justification**
>
> The stainless steel piping is a 2-inch atmospheric vent line off of the 30-inch Circulating Water System line that connects the discharge structure to the forebay. This vent line was installed in December 2003 and is approximately 20

feet long from where it attaches to the top of the 30-inch line. All but about three feet of this line is underground.

The vent line is fabricated from 2-inch nominal, ASTM A-312, Schedule 80 pipe. Since the piping is an atmospheric vent, adequate pipe wall thickness is provided to ensure that its function will be maintained even if unanticipated aging occurs. Consistent with the NUREG-1801, Section XI.M34 program, the piping is coated and wrapped. It is recognized that coating and wrapping stainless steel piping could interfere with the normal surface passivation of stainless steel.

Therefore, even though the program includes a material not included in the NUREG-1801, Section XI.M34 program, the combination of the limited amount of stainless steel piping, the design of the piping, the recent installation, and the planned inspections provide an equivalent assurance that the intended function will be maintained for the stainless steel piping as for the steel piping.

Program Elements Affected

- **Element 1: Scope of Program**

  The Buried Piping and Tanks Program manages stainless steel, which is not a material in the scope of the NUREG-1801, Section XI.M34 program. However, including stainless steel in the program does not introduce any new aging effects not considered in the NUREG-1801, Section XI.M34 program.

RAI B2.1.7-2

<u>Background</u>

The applicant states that its proposed aging management program Buried Piping and Tanks Inspection (B2.1.7) (LRA AMP) is consistent with the aging management program Buried Piping and Tanks Inspection (XI.M34) contained in the GALL Report (GALL AMP). Section 3 (Parameters Monitored/Inspected) of the LRA AMP states that uncoated buried steel is included. The GALL AMP includes only coated steel.

<u>Issue</u>

The inclusion of uncoated steel in the LRA AMP is considered an exception to the GALL AMP.

<u>Request</u>

Please rewrite the LRA AMP showing the inclusion of uncoated steel as an exception. Please demonstrate that the procedures specified in the LRA AMP will adequately manage corrosion of buried uncoated steel piping.

DEK Response

The LRA is supplemented to replace the following wording in LRA Appendix B, Section B2.1.7, Exceptions to NUREG-1801:

> The Buried Piping and Tanks Inspection Program takes no exceptions to the recommendations of NUREG-1801, Section XI.M34, 'Buried Piping and Tanks Inspection.'

The above wording will be replaced with the following:

> **Exception 2:** Use of Uncoated Material in the NUREG-1801, Section XI.M34 Program
>
> The program manages the aging of uncoated steel though the NUREG-1801, Section XI.M34, program. However, this program only includes the use of coated or wrapped components.
>
> **Justification**
>
> The inclusion of uncoated steel in the Buried Piping and Tanks Inspection Program is an exception to the recommendations of NUREG-1801, Section XI.M34, "Buried Piping and Tanks Inspection." The only uncoated steel included in the program is the Emergency Diesel Generator fuel oil tank hold-down straps. The Emergency Diesel Generators fuel oil tanks hold-down straps are structural components used to attach the buried Emergency Diesel Generator fuel oil tanks to their foundations. Aging effects on the external surfaces of the buried fuel oil

tanks is managed by the Buried Piping and Tanks Inspection Program. The hold-down straps are accessible during the external surface inspection of the fuel oil tanks and will be inspected under the same program.

Program Elements Affected

- **Element 1: Scope of Program**

  The Buried Piping and Tanks Program manages the Emergency Diesel Generator fuel oil tank hold-down straps, which are not coated or wrapped. Though uncoated components are not included in the scope of the NUREG-1801, Section XI.M34 program, including uncoated steel in the program will help ensure that the intended functions of the Emergency Diesel Generators fuel oil tanks are maintained throughout the period of extended operation.

- **Element 2: Preventive Actions**

  The Emergency Diesel Generator fuel oil tank hold-down straps are not coated or wrapped. The preventive actions will include inspection of the hold-down straps in conjunction with the inspection of the external surface of the buried Emergency Diesel Generator fuel oil tanks. The need to subsequently wrap or coat the straps will be evaluated by Engineering following each inspection.

- **Element 3: Parameters Monitored/Inspected**

  The NUREG-1801, Section XI.M34 program requires monitoring the integrity of coatings and/or wrappings that are directly related to mitigation of corrosion damage of buried component external surfaces. The Emergency Diesel Generator fuel oil tank hold-down straps are not coated or wrapped. The hold-down straps will be inspected and monitored for loss of material during the inspection of the Emergency Diesel Generator fuel oil tanks.

- **Element 4: Detection of Aging Effects**

  As identified in LRA Appendix B, Section B2.1.7, a representative sample of the Emergency Diesel Generator fuel oil tank hold-down straps will be inspected prior to entering the period of extended operation. An engineering evaluation will determine whether additional periodic inspections are required during the period of extended operation. The inspection criterion is evidence of loss of material, which is the aging effect applicable to the hold-down straps. The planned visual inspections are adequate to detect this aging effect.

LRA AMP B2.1.8, Closed-Cycle Cooling Water System

RAI B2.1.8-1

Background

LRA AMP B2.1.8, "Closed-Cycle Cooling Water System," manages the aging effects of cracking, loss of material, and reduction of heat transfer for the steel, stainless steel, and copper alloy piping, heat exchangers, and other components in the Component Cooling System, Emergency Diesel Generator cooling water subsystems, and Control Room Air Conditioning System. The program consists of water chemistry guidelines, including the use of inhibitors, in accordance with the EPRI Report 1007820, Revision 1, and performance monitoring to verify the effectiveness of the chemistry control program. The applicant claims that AMP B2.1.8 is consistent with GALL AMP XI.M21.

Issue

The AMP takes an exception (Exception 2) to the "preventive action" program element in that the program is implemented using the guidance of EPRI 1007820, Revision 1 (2004), instead of EPRI 107396 (1997), recommended by the GALL Report. The applicant stated that the new revision provides more prescriptive guidance and has a more conservative monitoring approach. The applicant further stated that implementation of EPRI 1007820 results in specific chemistry action levels that are more restrictive than those allowed in EPRI 107396.

Request

If the chemistry action levels are more restrictive, the exception should also affect "acceptance criteria" program element. Revise the AMP B2.1.8, Exception 2, to indicate that program elements affected include "preventive actions" and "acceptance criteria."

DEK Response

A review of LRA Appendix B, Section B2.1.8, "Closed-Cycle Cooling Water System," Exception 2, has been performed. It has been concluded that *Element 6: Acceptance Criteria* should have been included in the exception to the NUREG-1801, Section XI.M21 AMP as identified in RAI B2.1.8-1. The LRA is supplemented to include the following paragraph in Appendix B, Section B2.1.8, Exception 2, Program Elements Affected:

- **Element 6: Acceptance Criteria**

  The implementation of EPRI 1007820 results in specific chemistry action levels that are more restrictive than those allowed in TR-107396.

RAI B2.1.8-2

Background

LRA AMP B2.1.8, "Closed-Cycle Cooling Water System," manages the aging effects of cracking, loss of material, and reduction of heat transfer for the steel, stainless steel, and copper alloy piping, heat exchangers, and other components in the Component Cooling System, Emergency Diesel Generator cooling water subsystems, and Control Room Air Conditioning System. The program consists of water chemistry guidelines, including the use of inhibitors, in accordance with the EPRI Report 1007820, Revision 1, and performance monitoring to verify the effectiveness of the chemistry control program. The applicant claims that AMP B2.1.8 is consistent with GALL AMP XI.M21.

Issue

The AMP takes an exception (Exception 4) to the "parameters monitored or inspected" program element in that thermal performance testing is not performed for the heat exchangers included in the Component Cooling System cooling loop that are part of other systems or the Emergency Diesel Generator (EDG) cooling water subsystem heat exchangers and lube oil coolers. The applicant stated that in lieu of thermal performance testing, the heat exchangers are periodically inspected and flushed. In addition, the tubes of the EDG cooling water heat exchangers are periodically eddy current tested.

Request

Indicate the frequency for the periodic inspection and flushing of the above-referenced heat exchangers and lube oil coolers and provide a basis for specifying this frequency. In addition, please provide information on operating experience to verify the effectiveness of this program.

DEK Response

As a clarification to the Issue stated in RAI B2.1.8-2, only the Emergency Diesel Generator (EDG) cooling water subsystems heat exchangers and lube oil coolers are inspected and flushed. As described in LRA Appendix B, Section B2.1.8, Exception 4, the heat exchangers included in the Component Cooling System cooling loop that are part of other systems are not routinely inspected and flushed since the Component Cooling System is in continuous operation and the system performance, including system flow rates and temperatures, is monitored.

The EDG cooling water subsystems heat exchangers and lube oil coolers are drained and flushed every 18 months during refueling outages. In addition, the tube-side (i.e., raw water side) of the EDG cooling water subsystem heat exchangers are cleaned and visually inspected, and eddy current testing of the tubes is performed, during each refueling outage. The EDG lube oil coolers are exposed to treated closed-cycle cooling water and lubricating oil and are not expected to be subject to significant fouling or corrosion. Therefore, the cleaning and inspection of these coolers is based on EDG performance testing parameters and is not routinely scheduled.

No significant performance or material degradation has been identified for the Emergency Diesel Generator cooling water subsystem heat exchangers and lube oil coolers related to the closed-cycle cooling water environment. Additionally, the surveillance testing for the EDGs confirms that the thermal performance of the heat exchangers and lube oil coolers is consistent with the heat removal requirements to support EDG function. Therefore, the activities performed as described in Exception 4 to the Closed-Cycle Cooling Water System Program effectively maintain the intended function of these heat exchangers.

RAI B2.1.8-3

Background

LRA AMP B2.1.8, "Closed-Cycle Cooling Water System," manages the aging effects of cracking, loss of material, and reduction of heat transfer for the steel, stainless steel, and copper alloy piping, heat exchangers, and other components in the Component Cooling System, Emergency Diesel Generator cooling water subsystems, and Control Room Air Conditioning System. The program consists of water chemistry guidelines, including the use of inhibitors, in accordance with the EPRI Report 1007820, Revision 1, and performance monitoring to verify the effectiveness of the chemistry control program. The applicant claims that AMP B2.1.8 is consistent with GALL AMP XI.M21.

Issue

The applicant's AMP does not specify a monitoring frequency for nitrate levels in the component cooling water system, which utilizes a nitrite/molybdenate corrosion control program. However, EPRI Report 1007820, Revision 1 specifies that nitrate levels for such systems be monitored on a monthly basis for both Tier 1 and Tier 2 systems (EPRI Table 5-3).

Request

Provide a justification for not performing monthly monitoring of the nitrate levels in the closed cooling water system.

DEK Response

EPRI Report 1007820, Revision 1, "*Closed Cooling Water Chemistry Guideline*," Section 7.2.7, states that an increase in nitrate concentration is primarily an indicator of the presence of nitrifying bacteria. Section 7.2.8 of the report also states that ammonia can be produced by denitrifying bacteria in nitrite and nitrite/molybdate-treated systems. Additionally, ammonia can be measured as a possible indicator of denitrifying bacteria.

The nitrification process present in the closed-cooling water systems can lead to the formation of both ammonia and nitrates. Therefore, monitoring for either nitrates or ammonia can indicate the presence of bacteria. The formation of nitrates also results in a reduction of nitrites.

Component Cooling Water System nitrite concentration is monitored on a monthly basis. Component Cooling Water System ammonia concentration is monitored on a quarterly basis. Quarterly monitoring of ammonia, combined with monthly monitoring of nitrite concentration, verifies system chemistry stability and provides an indication that unacceptable levels of nitrates are not present in the Component Cooling System and is consistent with the intent of EPRI Report 1007820 guidelines.

LRA AMP B2.1.9, Compressed Air Monitoring

RAI B.2.1.9-1

Background

In LRA Appendix B, Section B.2.1.9, the applicant stated that the Compressed Air Monitoring Program is consistent with the program in the GALL Report except for the exception regarding lack of leak testing and the enhancement to implement ASME OM-S/G-1998, Part 17, and EPRI TR-108147. In the LRA, the applicant's program with the enhancement referred to the following technical basis references: ISA-S7.0.01-1996, U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-14, ASME OM-S/G-1998, Part 17, and EPRI TR-108147. The applicant also stated that EPRI TR-108147, which the applicant committed to implement, is the latest revision of EPRI NP-7079.

In contrast, the technical basis references of the applicant's program did not include NRC Information Notices (IN) 81-38, IN 87-28, IN 87-28 Supplement 1 or Institute of Nuclear Power Operations Significant Operating Experience Report (INPO SOER) 88-01. It is noted that the GALL Report recommends GL 88-14 to be augmented by the references that were not included in the applicant's program.

It is also noted that IN 87-28 Supplement 1 transmitted to the applicant NUREG-1275, Volume 2 "Operating Experience Feedback Report-Air System Problems," which addressed the concerns related to instrument air system failures and recommendations for corrective actions. In addition, INPO SOER 88-01 described the recommendations for operations, training, maintenance and design/analysis to prevent and mitigate instrument air system failures.

Issue

It is not clear whether the applicant's program is consistent with the Compressed Air Monitoring Program in the GALL Report in terms of applicable references for the technical basis of the program.

Request

If any of the IN 81-38, IN 87-28, IN 87-28 Supplement 1, NUREG-1275 Volume 2, and INPO SOER 88-01 is not applicable as a technical basis reference for the applicant's program, describe which reference is not applicable. Justify why the applicant's approach without the reference is adequate for the aging management or describe the actions for the applicant to take in relation to this potential issue.

DEK Response

Information Notice (IN) 81-38, IN 87-28, IN 87-28 Supplement 1, NUREG-1275, Volume 2, and INPO SOER 88-01 are applicable to the Compressed Air Monitoring Program. A change has been initiated to include these technical references in the program basis document as part of the next revision to the program.

RAI B.2.1.9-2

Background

In the applicant's chemistry procedure for air quality control, CHEM-44.001 Rev. B, "Instrument Air and Diesel Air Start Air Quality Specification," dated March 22, 2007, the inspection frequency for dew point is once a year as described in Section 5.3 of the chemistry procedure. In addition, Section 5.3 of the applicant's procedure does not specify any "Action Level" for hydrocarbon content or particulate size, while the "Action Level" for the dew point was ≥22 °F.

Issue

The ANSI/ISA-7.0.01-1996, which is one of the applicant's technical references, recommends shift monitoring for pressure dew point if a monitored alarm is not available. In addition, the staff found a need to clarify why "Action Level" was not specified for hydrocarbon content or particulate size.

Request

- *Clarify why the applicant's inspection frequency for pressure dew point is not consistent with the recommendation of ANSI/ISA-7.0.01-1996 even though the applicant claimed the consistency between the program and the ANSI/ISA-7.0.01-1996.*
- *Clarify why no "Action Level" was specified for hydrocarbon content or particulate size in the chemistry procedure.*
- *If necessary, describe the actions for the applicant to take in relation to the foregoing potential issues.*

DEK Response

The pressure dew point for the instrument air system is monitored and recorded each shift during plant operator rounds using the installed in-line dew point monitor. Therefore, the inspection frequency for instrument air system dew point monitoring is consistent with the guidelines provided in ANSI/ISA-7.0.01-1996, *Quality Standard for Instrument Air*.

The pressure dew point for the EDG air start subsystem is monitored annually. This system is typically in a standby mode and there is minimal demand for compressed air flow except when an EDG start signal is generated. Since there is little demand on the system, there is limited potential for introduction of moisture through compressor operation. Therefore, frequent dew point monitoring is unnecessary and would not provide meaningful information related to the compressed air quality. The system includes an air dryer that is maintained in service on a continuous basis such that moisture is removed from incoming compressed air during compressor operation. In addition, the air receivers in the system are checked daily for accumulation of condensation and are historically moisture-free. A review of compressed air monitoring data indicates that the pressure dew point has been within specification over the past several years. On this basis, the current annual pressure dew point monitoring has been effective in maintaining acceptable air quality in the EDG air start subsystem.

A change has been initiated through the Corrective Action Program to add an action level specification to the hydrocarbon and particulate content sample parameters in the chemistry procedure for compressed air quality control.

RAI B.2.1.9-3

Background

In element 3 of AMP XI.M24, the GALL Report recommends to confirm the emergency procedures and training. In conjunction with GL 88-14, NUREG-1275, Volume 2 (Part I, Section 9.0) recommends that anticipated transient and system recovery procedures and related training for loss of air systems events should be reviewed for adequacy and revised as necessary. NUREG-1275, Volume 2 also recommends that the plant personnel should be trained in the anticipated transient and system recovery procedures to respond to loss-of-air systems events.

Issue

The staff reviewed the LRA and Attachment 1, "Implement Procedures," of applicant's Technical Report KLR-1324, "Compressed Air Monitoring." The staff did not find a reference that directly describes the emergency procedures or training schedules related to the compressed air monitoring program.

Request

- *Provide relevant references for the emergency procedures on loss-of-air-systems events.*
- *Provide relevant references and schedules for the training on loss-of-air-systems events, anticipated transient and system recovery procedures, and compressed air systems.*

DEK Response

Abnormal Operating Procedure OP-KW-AOP-AS-001, "Loss of Instrument Air," is implemented by Operations to manage and recover from events that result in decreasing instrument air pressure. In accordance with the Long Range Training Plan (2004 through 2009) for the Kewaunee Licensed Operator Requalification Training Program, licensed plant operators are required to be trained on loss of instrument air events at least every two years, and must receive a minimum of 2 hours of training.

RAI B.2.1.9-4

Background

In LRA Appendix B, Section B.2.1.9, the applicant described the exception of the applicant's Compressed Air Monitoring Program that leak testing is not performed for the Station and Instrument Air System distribution network. In comparison, as an enhancement of the program, the applicant committed to incorporate the compressed air system testing and maintenance recommendations from ASME OM-S/G-1998, Part 17 and EPRI TR-108147 and to identify these documents as part of the program basis. In contrast with the program exception, ASME OM-S/G-1998, Part 17 and EPRI TR-108147 recommend leak tests such as:

- *pressure decay test on the distribution network as one of the recommended tests for the case that compressor loading indicates an increase in system leakage (ASME OM-S/G- 1998, Part 17, Section 5.3.3; EPRI TR-108147, Section 8.9.2)*
- *air leak test with a soap solution to piping joints and connections (EPRI TR-108147, Section 8.9.2)*

The staff noted that one of the major purposes of the leak testing is to identify the location of leaks as described in EPRI TR-108147 Section 8.9.2. In addition, the LRA indicated that only the program element, "Detection of Aging Effect," is affected by the exception and enhancement.

Issue

The exception regarding lack of leak testing is in apparent conflict with the technical basis references cited for the enhancement of the program. The staff also noted that, based on the applicant's technical information and program elements of the GALL Report program, each of the exception and the enhancement is regarded to affect the program elements, "Scope of Program," "Preventive Actions," "Parameters Monitored/Inspected," and "Monitoring and Trending," in addition to "Detection of Aging Effect," as all foregoing elements involve leak testing.

Request

- *Clarify how the applicant's program can identify the locations of air leakage without leak testing for the distribution network.*
- *Clarify whether leak tests for the distribution network will be performed as the technical basis references recommend and the applicant committed to in the program enhancement.*
- *Clarify whether each of the exception and the enhancement applies only to the program element, "Detection of Aging Effect."*

- *If necessary, describe the actions for the applicant to take in relation to the foregoing potential issues.*

DEK Response

LRA Appendix B, Section B2.1.9, Exception 1 is an exception to the recommendations of NUREG-1801, Section XI.M24, "Compressed Air Monitoring," and not to the aging management program references. This occurs because there is a difference between the recommendations of the NUREG-1801 and the recommendations of the reference documents.

NUREG-1801, Section XI.M24 is explicit that frequent leak testing is intended to be part of the program. The Program Description states the program includes, "...frequent leak testing of valves, piping, and other system components, especially those made of carbon steel and stainless steel..." In addition, Element 1 states, "The AMP includes frequent leak testing of valves, piping, and other system components, especially those made of carbon steel and stainless steel..."

The program reference documents identified in LRA Appendix B, Section B2.1.9, Enhancement 1 are ASME OM-S/G-1998, "Standards and Guides for Operation and Maintenance of Nuclear Power Plants," Part 17, dated February 12, 1999 and EPRI TR-108147, "Compressor and Instrument Air System Maintenance Guide," dated March 1998. Regarding leakage testing, ASME OM-S/G-1998, Section 5.3.3, states, "If compressor loading indicates an increase in system leakage, perform a pressure decay test ..." EPRI TR-108147, Section 8.9.2, states, "Where damage is observed [during walkdowns], the piping should be checked for leaks...A frequently used, reliable method for locating air leaks is to systematically apply a soap solution to the piping joints and connections."

Though both OM-S/G-1998 and TR-108147 address leak testing, both documents advocate leak testing as part of a troubleshooting process when leakage is suspected and not as a periodic preventative maintenance activity. Therefore, there is a technical difference between guidance in NUREG-1801, Section XI.M24 and the two industry documents.

The exception to the recommendations of NUREG-1801 is necessary to clarify that frequent leak rate testing is not performed for the Station and Instrument Air System. However, as identified in LRA Appendix B, Section B2.1.9, periodic leak testing is performed for the Emergency Diesel Generator air start systems. The exception does not imply that leak testing would not be performed when there are indications of leakage in the Station and Instrument Air System and the source of the leakage is not readily apparent. This type of "as needed" rather than "preventative" leak testing would be performed when required, per OM-S/G-1998 and TR-108147.

Based on station operating experience, Operations and Engineering walkdowns identify leak sources prior to other indications of system leakage. The Station and Instrument Air distribution system has not experienced a significant number of leaks. However, as noted above, performing leak testing as part of a troubleshooting activity is a tool to be used to locate a suspected leak. This approach is consistent with OM-S/G-1998 and TR-108147.

Based on the discussion above, LRA Appendix B, Section B2.1.9 Enhancement 1 is correct since the applicability of industry guidance regarding leak testing is unchanged. However, to improve clarity in the Compressed Air Monitoring Program requirements, the LRA Appendix B, Section B2.1.9, Exception 1 is supplemented to include the following:

Frequent leak testing is not performed on the Station and Instrument Air System distribution network as recommended by NUREG-1801, Section XI.M24.

The **Justification** for Exception 1 should include the following bulleted item:

- System walkdowns have proven effective in identifying and locating air distribution system leakage. Leak testing is used as a diagnostic tool when needed.

Each of the additional elements identified in this RAI were re-evaluated for possible impact by the program enhancement and revised exception. The LRA is supplemented to include the following in LRA Appendix B, Section B2.1.9, Enhancement 1, Program Elements Affected:

- Element 2: Preventive Actions

  Implementation of the preventive maintenance practices will ensure that the compressed air systems can perform their intended function.

- Element 5: Monitoring and Trending

  Implementation of the monitoring practices recommended in OM-S/G-1998 and TR-108147 will ensure that the compressed air systems can perform their intended function.

RAI B.2.1.9-5

Background

The element, 'Acceptance Criteria," of the program in the GALL Report recommends that acceptance criteria be established for the system and for individual components that contain specific limits or acceptance ranges based on design basis conditions and/or components vendor specifications. The program element also recommends that the testing results be analyzed to verify that the design and performance of the system in accordance with its intended function.

Issue

The staff found that the applicant's program documents did not clearly indicate whether the applicant's program established acceptance criteria for the following parameters of the compressed air systems.

- *Minimal operational time for each special service air accumulator and its associated check valves upon loss of the main air system*
- *Load and unload times for compressors*
- *Inlet and outlet coolant temperatures of the coolant in the compressor intercoolers and aftercoolers*
- *Set pressures of compressors and receiver pressure-relief valves*
- *Differential pressure through each dryer*

Request

- *Clarify whether relevant acceptance criteria are established and documented for the foregoing parameters.*
- *If any of the parameters does not have an acceptance criterion, justify why lack of the acceptance criterion for the parameter is acceptable for the aging management. Otherwise, describe the actions for the applicant to take in relation to the acceptance criteria.*

DEK Response

The minimal operational time for each special service air accumulator and its associated check valves upon loss of the main air system is a design consideration for the Station and Instrument Air System and is not related to plant aging. Although the discs associated with the accumulator check valves are in the scope of license renewal and provide a pressure boundary function upon loss of the main air system, the discs are active components not requiring aging management review. Therefore, the minimal operational time for each special service air accumulator and its associated check valves is not monitored by the Compressed Air Monitoring Program. Loss of material of the check valve bodies and accumulators is managed by the Compressed Air Monitoring Program.

The unload times for the in-service compressors in the Station and Instrument Air System are monitored each shift in accordance with approved procedures.

By design, it is not possible to monitor load and unload times for the compressors in the Emergency Diesel Generator air start subsystem. The Emergency Diesel Generator air start subsystem compressors are designed to automatically cycle based on air start tank pressure. As identified in LRA Appendix B, Section B2.1.9, periodic leak testing is performed on the Emergency Diesel Generator air start subsystems. The Emergency Diesel Generator air start subsystem is required when the Emergency Diesel Generators are operating. Therefore, Emergency Diesel Generator air start subsystem compressors do not cycle frequently when the Emergency Diesel Generators are not in operation.

The pressure in the Emergency Diesel Generator air start tanks is continuously monitored and alarmed in the control room. Accordingly, the operators would be alerted to an unexpected pressure drop in the air start tanks. Compressors F and G in the Station and Instrument Air System, which are the normally operating compressors, and the Emergency Diesel Generator air start subsystem air compressors are all air cooled. Therefore, monitoring of compressors F and G coolant temperatures is not required. Compressors A, B, C in the Station and Instrument Air System are water cooled. These compressors are not normally in operation but are maintained and routinely tested. The coolant temperatures are monitored during testing in accordance with approved test procedures.

The set pressures for the Station and Instrument Air System and the Emergency Diesel Generator air start subsystem compressors and receiver pressure-relief valves are routinely monitored in accordance with approved maintenance procedures. Bench testing is performed and the as-found set pressures are documented. The acceptance criteria are listed for each relief valve in the applicable maintenance procedure. If the acceptance criteria are not met, the relief valves are either adjusted or replaced.

For the Station and Instrument Air System, the differential pressure (DP) through the dryers is continuously monitored. The dryers are automatically bypassed in the event of high differential pressure across the dryer. Bypass of the dryers is annunciated in the Control Room. The setpoint at which dryer bypass occurs is established by approved procedures.

For the Emergency Diesel Generator air start subsystem, the differential pressure through the dryers is not monitored because the compressors operate intermittently.

The dryers are cleaned on an annual basis in accordance with approved maintenance procedures.

LRA AMP B2.1.10, External Surfaces Monitoring

RAI B2.1.10-1

Background

LRA Section B2.1.10 describes the existing External Surfaces Monitoring Program as consistent, with GALL AMP XI.M36 "External Surfaces Monitoring," with enhancements and no exceptions. The referenced GALL defines this as a condition monitoring program, i.e., the program subscribes to inspection procedures to identify the presence and extent of aging effects.

In the referenced section of the LRA, the applicant professes that its External Surfaces Monitoring Program manages "the aging effects of change in material properties, cracking, delamination, loss of material, and hardening and loss of strength" by visually inspecting the external surfaces of in-scope components (e.g. piping and its supports) and structural (members and commodities). Materials monitored also include stainless steel, aluminum, copper, and elastomers. The GALL Report AMP XI.M36, however, only applies to materials constructed of steel. NUREG-1801, Vol. 2, Rev 1, Section IX, page IX-12, defines steel to include only "carbon steel, alloy steel, cast iron, gray cast iron, malleable iron, and high strength low alloy [(HSLA)] steel." The applicant has modified their AMP to include other metallics and selected elastomers as part of their external surfaces monitoring program.

Issue

The intent of the XI.M36 program is to monitor the aging effects of steel material which can be regularly monitored and easily identified through visual inspections. It does not specify how to monitor the aging effects of the other applicant referenced materials. Rust on carbon steel materials is easily identifiable. It manifests itself as brownish/orange bubbles or layers. Copper and aluminum, exposed to an open air environment, oxidize also, but their oxides could be hard to spot.

Request

- *Justify why the inclusion of stainless steel, aluminum, copper, and elastomers to this AMP does not constitute an exception to the GALL Report XI.M36.*
- *Define how corrosion in other metallics such as aluminum or stainless steel will be tracked to avert sudden loss of a system, structure, or (SSC) functionality.*
- *Discuss how the "scratch, sniff, and stretch" tests identified in the Aging Assessment Field Guide of EPRI (audited reference 9) as potential polymer/elastomer tests to monitor their health could be accomplished strictly via visual observation.*

DEK Response

As described below, the inclusion of stainless steel, aluminum, copper, and elastomers in the External Surfaces Monitoring Program constitutes an exception to NUREG-1801, Section XI.M36, "External Surfaces Monitoring."

The metallics included in the scope of the External Surfaces Monitoring Program are aluminum, copper alloys, stainless steel, and steel. The aging effect managed for these materials is loss of material, which is evident by external surface irregularities or localized discoloration before loss of function occurs. The visual inspections performed by the External Surfaces Monitoring Program are capable of identifying degradation for both steel and non-steel metallic components.

The general material condition and inspection parameters monitored include:

- Boric acid buildup
- Poor material condition
- General corrosion/corrosion product build-up
- Coating degradation
- Accumulation of dirt/debris
- Evidence of leakage.

As identified in LRA Appendix B, Section B2.1.10, Enhancement 2, training will be provided for the Operations, Engineering, and Health Physics personnel performing the program inspections and walkdowns. The training will address the requirements of the External Surfaces Monitoring Program to document general material condition and inspection parameters with sufficient detail to support monitoring and trending of aging effects.

The External Surfaces Monitoring Program also incorporates the "scratch, sniff, and stretch" technique from the EPRI Aging Assessment Field Guide to observe and detect external aging of elastomers.

Therefore, the External Surfaces Monitoring Program will adequately manage the aging effects for the metallics and selected elastomers within the scope of the program to ensure the intended functions of the components are maintained.

The External Surfaces Monitoring Program is supplemented to include an exception to the recommendations of NUREG-1801, Section XI.M36, to manage aging of stainless steel, aluminum, and copper materials and of elastomers using techniques other than visual. The following wording is in LRA Appendix B, Section B2.1.10, Exceptions to NUREG-1801:

The External Surfaces Monitoring Program takes no exceptions to the recommendations of NUREG-1801, Section XI.M36, "External Surfaces Monitoring."

This statement is replaced with the following:

Exception 1: Use of Materials and Aging Detection Methods Not in the NUREG-1801, Section XI.M36 Program

The program manages the aging of stainless steel, aluminum, copper, and elastomers. However, the NUREG-1801, Section XI.M36 program includes only steel as a material managed by the program. The program detects external aging of elastomers using techniques other than visual. The NUREG-1801, Section XI.M36 program relies on only visual observations to detect aging.

Justification

While the scope of the NUREG-1801, Section XI.M34 program includes only steel, there are other non-steel materials that must be monitored for external aging. With exceptions and enhancements to the NUREG-1801, Section XI.M34 program, the External Surfaces Monitoring Program can adequately manage the external aging effects of non-steel materials.

With respect to detection of aging effects, the NUREG-1801, Section XI.M34 program relies on visual observations to detect external aging. The External Surfaces Monitoring Program will incorporate the "scratch, sniff, and stretch" technique to observe and detect external aging of elastomers. This technique is recognized as an acceptable method in the EPRI Aging Assessment Field Guide.

Program Elements Affected

- Element 1: Scope of Program

  The External Surfaces Monitoring Program manages the external aging effects for stainless steel, aluminum, copper, and elastomers, which are not materials in the scope of the NUREG-1801, Section XI.M34 program.

- Element 4: Detection of Aging Effects

  The External Surfaces Monitoring Program relies on techniques, other than visual, to detect external aging of elastomers. The NUREG-1801, Section XI.M34 program relies solely on external visual observations to detect aging.

RAI B2.1.10-2

Background

In the referenced section of the LRA, the applicant professes that its External Surfaces Monitoring Program manages "the aging effects of change in material properties, cracking, delamination, loss of material, and hardening and loss of strength" by visually inspecting the external surfaces of in-scope components (e.g. piping and its supports) and structural (members and commodities).

Issue

Material properties refer to mechanical, electrical, thermal, magnetic, etc. attributes/capacities of each material to perform specific functions. The staff believes that the monitoring of changes in material properties need monitoring beyond just a visual walkdown inspection.

Request

- *Provide the basis for monitoring the aging effects of change in material properties with visual inspection only.*

DEK Response

The External Surfaces Monitoring Program is only used to manage the aging effect of change in material properties for the flexible connections in the ventilation system ducting and the Shield Building penetration seals.

The External Surfaces Monitoring Program will incorporate the "scratch, sniff, and stretch" technique to observe and detect external aging of elastomers, including these components. This technique is recognized as an acceptable method in the EPRI Aging Assessment Field Guide.

See the response to RAI B2.1.10-1 for additional information regarding the exception to the recommendations of NUREG-1801, Section XI.M36 related to elastomers.

RAI B2.1.10-3

Background

The LRA states, the External Surfaces Monitoring program takes a sampling approach for detecting aging effects and monitoring the condition of plant system, structure, and components (SSCs) in extended operation. It samples the SSCs by segregating the plant into areas containing the SSCs or structural commodities being evaluated. Areas range from portion of rooms, to entire rooms, floors of buildings, or entire buildings. The personnel performing the XI.M36 task, inspect only a "representative" sample of the materials/environment combinations.

Issue

AMP XI.M36 is a monitoring program, not a sampling program. Sampling, however, is allowed (NUREG 1800, Rev. 1) provided the samples (size, population) are adequate to characterize the effects of aging on the structures or components (SCs). There is no elaboration on the size or population of the samples other than a general statement on the materials and SCs defined in the scope. Provisions should also be included on expanding the sample size when degradation is detected in the initial sample.

Request

If the applicant intends to sample then provide additional details regarding the sampling methodology such as:

- *The areas and sample sizes.*
- *What is the basis for selecting these areas/samples?*
- *Did the applicant include previous failure histories in defining the samples? If so, did the applicant biased his samples?*
- *Are the samples biased toward locations most susceptible to corrosion in the period of extended operations?*
- *What are the provisions to modify or expand the samples' sizes? How will the applicant do this?*

DEK Response

The phrase "representative sample" was incorrectly used in the Program Description for the External Surfaces Monitoring Program in LRA Appendix B, Section B.2.1.10. The External Surfaces Monitoring Program is a monitoring program that is consistent with NUREG-1801, Section XI.M39, "External Surfaces Monitoring."

Personnel performing the inspections required by the External Surfaces Monitoring Program inspect material/environment combinations in a designated area and look for indications of aging, such as loss of material, loss of sealing, or leakage on the components, structural members, and structural commodities in that area. Therefore, the inspections ensure a sufficient number of components are examined so that an overall assessment of component aging can be determined.

LRA AMP B2.1.11, Fire Protection

RAI B.2.1.11-1

Background

In its LRA, KPS proposed an exception to XI.M26 on the Halon and CO2 fire suppression systems testing frequencies. The GALL Report recommends a 6-month inspection and testing frequency for both the Halon and CO2 systems. To minimize interruption to the plant operation, KPS proposes to test the relay room CO2 subsystem and the turbine bearing CO2 subsystem every 18 months during the refueling outage. All other CO2 fire suppression systems are functionally tested on a semi-annual basis. The Halon systems are functionally tested on an annual basis.

Issues

The testing frequency of the Halon and two of the CO2 sub-systems exceeds the GALL recommended frequency.

Request

Please provide reason(s) based on the plant operating experience and other relevant factors to justify the extended functional testing cycle for the Halon and CO2 fire suppression systems.

DEK Response

Currently, the CO2 fire suppression systems, with the exception of the relay room and turbine bearing subsystems, are inspected and tested annually. This change was recently implemented based on the results of a review of system maintenance, testing, and out-of-service times. The review determined that an annual inspection and testing frequency met applicable code and insurance requirements, and was justified based on historical inspections and testing results. As a result, these CO2 systems are included within the scope of LRA Appendix B, Section B2.1.11, Exception 1. The inspection and testing frequency of the relay room and turbine bearing CO2 fire suppression systems remains at once every 18 months as stated in the LRA. Halon systems are tested annually.

The inspection and testing frequency for the Halon and CO2 fire suppression systems is consistent with the requirements of Nuclear Electric Insurance Limited (NEIL), the insurance provider for Kewaunee, and National Fire Protection Association (NFPA) codes as described in LRA Appendix B, Section B2.1.11. Based on the results of inspections and testing performed since 1973, there has been no significant aging-related degradation identified in these gaseous fire suppression systems. Therefore, the extended functional testing cycle provides adequate opportunity to observe system performance degradation prior to loss of intended function and the inspection and testing frequency is justified.

RAI B.2.1.11-2

Background

In its LRA, KPS proposed an enhancement to XI.M26 on the Reactor Coolant Pumps Oil Collection System Inspections. The GALL Report recommends the XI.M39 "Lubricating Oil Analysis," and XI.M32, "One-Time Inspection" AMPs (Ref: VII-G-26 and VII-G-27 on p. VII G-8 of the GALL Report, volume 2) for the material (steel) and environment (lubricating oil) combination. The LRA only credited a one-time inspection of the internal surfaces of the reactor coolant pump oil collection tank before the extended period of operation. The applicant stated that the one-time inspection was not the XI.M32 "One-Time Inspection" AMP. The lubricating oil analysis AMP was not specifically credited in this enhancement.

Issues

It is not clear to the reviewer as to why the XI.M32, "One-Time Inspection" and the XI.M39, "Lubricating Oil Analysis" AMPs are not credited to support this enhancement.

Request

Please provide the basis for not being consistent with the GALL Report recommendation for this material and environment combination to support this enhancement.

DEK Response

The reactor coolant pump oil collection system is a fire protection feature designed to capture oil in the event of leakage from the reactor coolant pump bearings and eliminate the potential for oil ignition due to contact with a hot surface. Any oil leakage that is captured by the system is collected in the reactor coolant pump oil collection tank for disposal. The steel tank is exposed internally to an air environment and can also be exposed to lubricating oil due to reactor coolant pump leakage.

The aging management review results for the reactor coolant pump oil collection tank are provided in LRA Table 3.3.2-18. Since the lubricating oil environment for the tank is from oil leakage from reactor coolant pump bearings, it was determined that management of tank aging by the Lubricating Oil Analysis Program described in LRA Appendix B, Section B2.1.17 would not be effective. In addition, although the aging management review conservatively concluded that loss of material due to corrosion is a potential aging effect, the internal air environment with the potential for minimal amounts of oil is not expected to be aggressive to the tank material and result in significant aging. Therefore, a specific visual inspection of the tank prior to the period of extended operation is provided as an enhancement to the Fire Protection Program, as described in LRA Appendix B, Section B2.1.11, "Fire Protection," Enhancement 3, in order to confirm that significant aging is not occurring. A visual inspection of the tank is adequate to identify signs of loss of material due to corrosion.

Therefore, the reactor coolant pump oil collection tank inspection performed prior to the period of extended operation under the Fire Protection Program, as enhanced, is adequate to manage the identified aging effect for this component and will provide reasonable assurance that the intended function of the tank will be maintained during the period of extended operation.

LRA AMP B2.1.13, Flux Thimble Tube inspection

RAI B.2.1.13-1

Background

In the LRA, the applicant stated that the flux thimble inspection program is consistent with the GALL Report with no exception or enhancement. The element, "Monitoring and Trending," of the GALL Report AMP recommends that the wall thickness measurements should be trended and wear rates should be calculated.

Issue

The LRA and related on-site program documentation do not clearly address how the program manages discrepancies between projected wear rates and measured wear rates.

Request

Explain how the AMP manages discrepancies between projected wear rates and measured wear rates, especially for cases where the discrepancies are big and unexpected.

DEK Response

Discrepancies noted between projected wear rates and measured wear rates are documented in the Corrective Action Program. An engineering evaluation of the discrepancy is performed and applicable corrective actions are developed based on the conclusions from the evaluation. The evaluation would include a review of the NDE data to determine validity, a review of the cause of the unexpected wear, and a new projection of thimble tube thickness based on the current inspection frequency. Corrective actions may include isolating the thimble tube, axially repositioning the thimble tube to move the wear scar away for the contact area, and/or changing the inspection frequency to ensure structural integrity of the thimble tubes until the next inspection.

RAI B.2.1.13-2

Background

The operating experience of this program in LRA Appendix B, Section B2.1.13 indicated that inspections were performed in 2000 and 2004.

Issue

The LRA did not clearly indicate that the results of the inspections performed in 2000 and 2004 demonstrate the adequacy of the program-defined inspection frequency and wear projection methodology.

Request

Provide relevant inspection results, including the actual wear of the two inspection periods which ended in 2000 and 2004, respectively, and demonstrate that the applicant's inspection frequency and wear rate projection methodology are adequate to manage the aging effect of the thimble tubes.

DEK Response

The table below shows the inspection results (percent through-wall) for all active wear scars from the 2000 and 2004 inspections, respectively. Wear scars from tube locations that were repositioned in 1994 are not shown below because subsequent eddy current testing has confirmed that these scars are not actively wearing. Additionally, the degradation forecast for Refueling Outage 30 in the fall of 2009 is included.

Tube Number	2000 Through-Wall Extent (%)	2004 Through-Wall Extent (%)	2009 Projection Using 2000-2004 Wear (%)
1	NDD *	NDD	1
2	37	35 (37) **	39
3	47	47	50
4	38	30 (38) **	40
5	NDD	NDD	1
6	32	32	34
7	39	41	43
8	NDD	NDD	1
9	28	27 (28) **	30
10	NDD	NDD	1

11	36	40	42
12	20	15 (20) **	21
13	37	36 (37) **	39
14	35	33 (35) **	37
15	42	41 (42) **	44
16	44	44	46
17	29	26 (29) **	31
18	23	22 (23) **	24
19 – Capped	N/A	N/A	N/A
20	17	17	18
21	41	38 (41) **	43
22	42	48	51
23	36	35 (36) **	38
24	29	28 (29) **	31
25	26	22 (26) **	27
26	36	43	45
27	43	40 (43) **	45
28	24	23 (24) **	25
29	NDD	NDD	1
30	46	48	51
31	42	43	45
32	44	44	46
33	47	40 (47) **	50
34	28	24 (28) **	30
35	NDD	10	11
36	NDD	NDD	1

* NDD = No detectable defect. A one percent through-wall scar was used in 2004 for projecting wear on tubes that were NDD both years.

** When the 2004 inspection result was less than the 2000 inspection result, the number was rounded up for future wear projections, i.e., the number in parentheses was used as the starting point for the projections.

Examination frequency is based upon plant-specific wear projections using results from the previous two inspection periods. The interval between examinations is established such that no flux thimble tube is predicted to incur wear that exceeds the acceptance criteria. The examination frequency is consistent with the NRC-accepted response to NRC Bulletin 88-09, "*Thimble Tube Thinning in Westinghouse Reactors.*"

Projected plant-specific wear is calculated consistent with the methodology defined in WCAP-12866, "*Bottom Mounted Instrumentation Flux Thimble Wear.*" The projected plant-specific wear rate calculation and data trending, using a technically justified conservative method as defined in WCAP-12866, is consistent with the recommendation of NUREG-1801, Vol. 2, "*Generic Aging Lessons Learned (GALL) Report,*" Section XI.M37, "Flux Thimble Tube Inspection."

Therefore, since the inspection frequency and wear rate projection methodology are based on accepted and conservative criteria, the management of wear of the thimble tubes is demonstrated.

RAI B.2.1.13-3

Background

In the LRA, the applicant stated that the flux thimble inspection program is consistent with the GALL Report with no exception or enhancement. The element, "Acceptance Criteria," of the GALL Report AMP recommends that acceptance criteria such as percent through-wall wear should be established and technically justified to provide an adequate margin of safety to maintain the integrity of the reactor coolant system pressure boundary.

The program element also recommends that acceptance criteria different from those previously documented in NRC acceptance letters for the applicant's response to Bulletin 88-09 and amendments thereto should be justified.

Issue

The section for the program element, "Acceptance Criteria," in the on-site technical report, KLR- 1335, Revision 1 stated that the acceptance criterion of 80% through-wall wear requires the repositioning and isolation of the thimble tube. The report also stated that the 80% criterion was first used in 2004 and differs from the 60% limit discussed in the applicant's response to GL 88-09.

Request

- *In the applicant's program description, "GL 88-09" should be corrected to Bulletin 88-09. Clarify this issue.*
- *As the GALL Report recommends, justify why the current acceptance criteria provide an adequate margin of safety to ensure that the integrity of the reactor coolant system pressure boundary is maintained in consideration of the uncertainties of wall thickness measurements and projections.*

DEK Response

- The reference to 'GL 88-09' in Kewaunee License Renewal Technical Report KLR-1335, "Flux Thimble Tube Inspection," is a typographical error and should have been 'Bulletin 88-09'. A change has been initiated to correct this typographical error during the next revision of the report.
- The current acceptance criteria require a thimble tube with a wall thickness measurement of 60% through-wall wear to be repositioned if the plant-specific through-wall wear to the next inspection period is projected to be equal to or greater than 80%.

A thimble tube wall thickness measurement of 80% through-wall wear requires repositioning and isolation of the thimble tube.

The current acceptance criteria are consistent with the research and testing documented in WCAP-12866, "*Bottom Mounted Instrumentation Flux Thimble Wear.*" WCAP-12866 provides eddy current calibration standards that have reduced variation in thimble wear measurements leading to a refinement in the ability to predict thimble wear rates. Since the technique provides actual or conservative estimates of the depth of the wear scars, the addition of an uncertainty margin to the actual eddy current wall loss indications is not required.

Flux thimble tube segment collapse tests documented in WCAP-12866 show that the tubes have a high residual strength, even when subjected to wall loss on the order of 90 percent. The tests show tubes will retain their functional and structural integrity with up to an 85 percent wall loss for all plant operating modes when using the eddy current standard.

Therefore, the use of an 80% through-wall wear acceptance criterion, with corrective action initiated at a 60% through-wall measurement, provides an adequate margin of safety to ensure that the integrity of the reactor coolant system pressure boundary is maintained.

RAI B.2.1.13-4

Background

The work order instructions of the applicant for thimble tube eddy current inspection, WO# 03-011955 / PM50-032, indicated that WCAP#12866 shall be used to predict future tube degradation.

The staff noted that Section XIII, Conclusions, of WCAP-12866, "Bottom Mounted Instrumentation Flux Thimble Wear," states that the best approach to calculating future wall loss is to use the exponential equation, with an exponent value calculated using two previous cycle inspection results for a specific plant. The report also states that for plants which do not have two prior inspection points, a conservative exponent value of 0.67 may be used.

The applicant's report, "Thimble Tube Inspection Evaluation Report," under KNPP WO# 03- 11955 dated October 29, 2003, and attached information on the thimble tube degradation forecast suggest that the applicant's wear projection methodology might use an exponent of 0.67 rather than an exponent based on the previous two inspection results.

In addition, the WCAP report states that the changes in thimble or reactor hardware and changes in reactor coolant flow rate can change the thimble wear rate in a given plant and theses changes must be assessed when assessing future thimble wear.

Issue

In the applicant's response to NRC Bulletin 88-09, dated November 7, 1988, the applicant stated that the examination frequency after 1998 will be dependent on the results of the previous two tests. However, it is not clear whether the applicant's approach to define the exponent considers plant-specific inspection results.

The staff also found a need to clarify whether the program adequately manages the potential effect of hardware and flow rate changes on the thimble tube wear rates.

Request

- *Clarify what exponent is used for the wear projections. If the previous inspection results are not used to determine the exponent, demonstrate why the applicant's methodology on the exponent determination is in agreement with or conservative than the exponent determination based on the actual plant-specific inspection results.*
- *Describe how the applicant's program considers and manages the potential effect of changes in flow rates and thimble or reactor hardware on the wear rates.*

DEK Response

- Thimble tube wear projections are computed in accordance with the WCAP 12866, *Bottom Mounted Instrumentation Flux Thimble Wear,* exponential equation using an exponent value calculated based on the two previous cycle inspection results (i.e., 2000 and 2004 inspections). Additionally, the projection is computed using the WCAP recommended conservative exponent value of 0.67. The two calculated wear projections are compared to verify the 0.67 exponent provides a more conservative value. Projected wear rates determined subsequent to the 2004 inspection, using the 0.67 exponent, resulted in no projections of thimble tube wear exceeding the 80 percent through-wall limit.
- Changes to RCS flow rates or thimble or reactor hardware could only occur through a plant modification in accordance with the Kewaunee design control process. This process is procedurally controlled and includes the requirement for a safety review, in accordance 10 CFR 50.59, and review by affected plant organizations for impacts to plant programs and equipment. During the preparation and subsequent review of the plant modification package, changes to RCS flow rates or thimble or reactor hardware that could affect the thimble wear rate would be identified and assessed.

RAI B.2.1.13-5

Background *and* Issue

The applicant's Updated Final Safety Analysis Report (USAR) summary description in LRA Section A2.1.13 does not include NRC Bulletin 88-09 as a reference in contrast with the summary in SRP-LR Table 3.1-2.

Request

In the USAR summary description, include NRC Bulletin 88-09 as a technical reference and clarify whether the program implements the recommendations of NRC Bulletin 88-09.

DEK Response

NRC Bulletin 88-09 will be included as a technical reference and affirmed in the LRA Appendix A, USAR Supplement. The following will be added to the end of the last paragraph of LRA Appendix A, USAR Supplement, Section A2.1.13:

"The program implements the recommendations of NRC Bulletin 88-09, *Thimble Tube Thinning in Westinghouse Reactors*, as identified in WPSC letter NRC-88-2 dated January 6, 1989."

LRA AMP B2.1.14, Fuel Oil Chemistry

RAI B2.1.14-1

Background

In Exception #1 of LRA Section B2.1.14, the applicant states that KPS has not adopted the Standard Technical Specification as described in NUREG-1431 and the plant fuel oil specifications and procedures invoke requirements that are similar to the Standard Technical Specifications for fuel oil purity and fuel oil testing.

Issue

The staff noted that the meaning of the term "requirements that are similar" is not clear. The staff noted that the use of this term may also be subjective.

Request

Please provide a direct comparison between the Standard Technical Specifications and the KPS fuel oil specifications along with a justification for any difference in fuel oil purity and testing parameters.

DEK Response

According to Section 5.5.13 of NUREG-1431, "Standard Technical Specifications Westinghouse Plants," one purpose of the diesel fuel oil testing program is to establish acceptability of new fuel oil for use prior to addition to the fuel oil storage tanks. Per NUREG-1431, acceptability is determined by verifying that the new fuel oil has a flash point and kinematic viscosity within limits for ASTM 2D fuel oil. Similarly, new fuel oil specific gravity, water content and sediment content must also be verified within acceptable limits prior to addition to the fuel oil storage tanks.

The Kewaunee fuel oil sampling procedure for new fuel oil deliveries includes all of the above parameters except verification of kinematic viscosity. Although, verification of kinematic viscosity is not required prior to off-loading diesel fuel oil into the storage tanks, it is included in the new fuel testing that is sent off-site for laboratory analysis. The laboratory analysis for new fuel oil includes all parameters required for stored fuel oil testing, which is performed quarterly. The results of the new fuel laboratory analysis are normally provided within 14 days versus the 31 days stated in NUREG-1431. Operating experience to-date has revealed no problems associated with kinematic viscosity for fuel oil.

NUREG-1431 specifies a frequency of 31 days for determining total particulate concentration of the fuel oil to be $\leq$10 mg/l. The Kewaunee diesel fuel oil test frequency of quarterly sampling for particulates is consistent with NUREG-1801, Section XI.M30, "Fuel Oil Chemistry," and has the same concentration limit as NUREG-1431.

RAI B2.1.14-2

Background

In Exception #2 of LRA Section B2.1.14, the applicant states that KPS does not add fuel stabilizers to the diesel fuel oil. The applicant continues to state that the diesel generators are operated on a frequent basis which allows for the mixing of incoming new fuel oil and the day tanks are small in size so they experience a high turnover rate of fuel oil.

Issue

The LRA was not clear about whether this statement is in reference to the EDGs and/or the TSC DG and how often they are operated. The LRA was also not clear about size of the tanks and how much fuel is consumed in order to be considered as undergoing a high turnover rate.

Request

Please provide the basis for the statements made in LRA for justifying not using fuel stabilizer additives in the diesel fuel oil. Please be specific and consider the following in your justification:

- *the diesel generators that are in scope of the program*
- *the frequency these diesel generators are operated*
- *the operating volume of the fuel oil storage and day tanks*
- *the amount of fuel that is consumed in comparison to the size of the respective tanks*
- *the parameters that are monitored, which provide indication of fuel oil decomposition or degradation that warrant not using fuel stabilizers*

DEK Response

As indicated in LRA Section 2.3.3.19, "*Diesel Generator System*," the two Emergency Diesel Generators (EDGs) and the Technical Support Center Diesel Generator (TSC DG) and their fuel systems have been included within the scope of license renewal. There are two Fuel Oil Storage Tanks (35,000 gallons each) and four Fuel Oil Day Tanks (850 gallons each) for the two EDGs. One fuel oil tank and two day tanks serve each EDG. There is one Fuel Oil Storage Tank (10,000 gallons) and one Fuel Oil Day Tank (275 gallons) for the TSC DG.

The Fuel Oil Chemistry Program is a preventive program that includes monitoring fuel oil chemistry to manage loss of material from the internal surfaces of the fuel oil piping and components. LRA Appendix B, Section B2.1.14, "*Fuel Oil Chemistry*," states that stabilizers are not added to the diesel fuel oil and that, "The diesel generators are run on a frequent basis, which results in the consumption of fuel oil replaced with the mixing of the new fuel oil."

The EDGs are operated for a minimum of one hour once every four weeks during their monthly surveillance testing and are run for 24 hours once every 18 months. During an 18 month period, the EDGs consume an estimated 26,000 gallons of fuel. This equates to roughly 37% of the maximum capacity of the Fuel Oil Storage Tanks and over seven (7) times the capacity of the day tanks.

The TSC DG is run for a minimum of one hour once every four weeks for monthly surveillance testing. During an 18 month period, the TSC DG consumes an estimated 1435 gallons of fuel oil. This equates to roughly 14% of the maximum capacity of the Fuel Oil Storage Tank and over five (5) times the capacity of the day tank.

The fuel consumption during routine surveillance testing for the EDGs supports the Exception 2 conclusion that turnover keeps the fuel oil supply mixed with new fuel. Fuel turnover during testing for the TSC diesel is not as significant as with the EDGs. However, fuel oil turnover is not the sole basis for not using stabilizers to the fuel oil supply. The testing provided by the Fuel Oil Chemistry Program ultimately assures that fuel oil quality is being maintained and biological breakdown of the fuel is not occurring.

The frequency of testing on the three (3) bulk storage tanks and the five (5) individual day tanks is: 1) quarterly multi-level sampling of the bulk storage tanks; and, 2) quarterly sampling of the day tanks as committed in the response to RAI B2.1.14-3. The tests performed determine the condition of the fuel oil, by monitoring chemical properties to ensure there is no breakdown of the fuel oil.

The specific fuel oil parameters, with applicable reference documents, that are monitored for instability or breakdown of fuel oil are the following:

- Particulate Contamination - ASTM D-6217
- Kinematic Viscosity @ 40°C Min./Max. - ASTM D-445
- Distillation Temp. 90% pt. Min./Max. - ASTM D-86

Operating experience has not resulted in any indication of fuel oil breakdown. Therefore, the use of a fuel oil stabilizer is not warranted.

RAI B2.1.14-3

Background

In Exception #5 of LRA Section B2.1.14, the applicant states that KPS does not perform multi-level sampling of the fuel oil day tanks. Instead a one-gallon sample is taken from the bottom of the tank on a monthly basis to allow for a visual inspection for the presence of water and sediment.

Issue

The LRA did not provide the justification and the threshold/criteria that will be used for the visual inspection of the one-gallon samples taken from the day tanks on a monthly basis.

Request

- *Please provide a justification that a visual inspection of this sample is sufficient in-lieu of a laboratory analysis of the sample as described in ASTM D4057. Provide and justify the threshold/criteria that will be used for this visual inspection of the sample, clearly identifying when corrective actions will be taken. Clarify how a visual inspection is capable of quantifying the amount of water/sediment/particulates that is in the one-gallon sample of fuel oil.*
- *Clarify if there is some type of filter or filtration that exists between the respective fuel oil storage tank and fuel oil day tank that would limit the amount of contaminants entering the day tank.*
- *Clarify whether the sample that is taken from the fuel oil day tanks is a true bottom sample or is it taken from another type of configuration. If it is not a true bottom sample please clarify this other type of configuration and justify that there is not a need to remove the accumulated water/sediment/contamination from the tank bottom that is not flushed out during the monthly removal of the one-gallon sample.*

DEK Response

Laboratory testing of the emergency diesel generators (EDG) and technical support diesel (TSC) day tanks fuel oil will be performed consistent with the quarterly surveillance frequency for the fuel oil storage tanks and the acceptance criteria requirements specified in ASTM D4057. Multi-level testing of the day tanks is not warranted due to the relatively small volume of the day tanks and the high turnover of fuel oil due to periodic testing.

The sample points for the EDG and TSC day tanks tap off the supply lines to the diesels, so the samples are representative of what is being drawn or used by the diesel. The EDG fuel oil day tanks have a riser three inches from the bottom of the tank, while the TSC DG day tank provides for a true bottom sample. There is no filtration located between the respective fuel oil storage tanks and fuel oil day tanks.

As a result of this commitment for day tank sampling and laboratory analysis, the LRA Appendix B, Section B2.1.14 is supplemented by the removal of Exception 5.

As stated in the response to RAI B2.1.15-1, a one-time inspection will be performed on the fuel oil day tanks prior to the period of extended operation. The quarterly laboratory analysis combined with a confirmatory one-time inspection provides assurance that the effects of aging will be adequately managed through the period of extended operation.

The following commitment will be added to LRA Appendix A, USAR Supplement, Table A6.0-1:

Item	Commitment	Source	Schedule
30	Quarterly laboratory testing of the EDG and TSC DG day tank fuel oil samples will be performed. The testing and acceptance criteria will be consistent with that specified ASTM D4057	Fuel Oil Chemistry	Prior to the Period of Extended Operation

RAI B2.1.14-4

Background

After the issuance of Revision 1 of the GALL Report, the NRC has issued Information Notice (IN) 2009-02, "Biodiesel in Fuel Oil Could Adversely Impact Diesel Engine Performance". This Information Notice discusses potential issues that may occur with the use of B5 blend fuel oil, such as: suspended water particles, biodegradation of B5, material incompatibility, etc.

Issue

The LRA did not provide information discussing the concerns of IN 2009-02 and the acceptable or unacceptable use of bio-diesel at KPS.

Request

- *Provide a summary of the actions that were taken to determine the impact of IN 2009-02 and the use of bio-diesel fuel oil at KPS. If actions have not been taken yet, describe the actions that KPS will take to determine the impact of IN 2009-02 and the acceptable or unacceptable use of bio-diesel.*
- *If bio-diesel is currently being used at KPS, please describe any problems that KPS encountered with the use of bio-diesel and the associated corrective actions to prevent reoccurrence in the future.*
- *If bio-diesel has been determined to be not acceptable for use at KPS, please describe the actions taken and/or will be taken to prevent its addition into fuel oil supply. Please also describe actions that will be taken if it is determined that bio-diesel has been added into the fuel oil supply.*

DEK Response

NRC Information Notice (IN) 2009-02, "*Biodiesel in Fuel Oil Could Adversely Impact Diesel Engine Performance,*" indicates there is a potential for diesel fuel oil to contain up to 5 percent biodiesel, which could adversely impact engine performance. IN 2009-02 was evaluated for applicability to Kewaunee with the conclusion that infiltration of biodiesel is controlled by purchasing only Amoco Premier diesel fuel, in addition to specifically prohibiting biodiesel in the purchase order contract for new diesel fuel. A review of the current purchase specification for diesel fuel has verified that these controlling provisions remain in place.

The absence of biodiesel is verified as part of laboratory analysis which is governed by the station's fuel oil sampling and testing procedures. However, these results are not received until after the fuel is delivered and mixed with the existing stored fuel. If the presence of biodiesel fuel is identified in the laboratory analysis, the issue would be documented in the station Corrective Action Program where operability of the diesel generators would be evaluated along with implementation of corrective actions.

LRA AMP B2.1.15, Fuel Oil Tanks Inspections

RAI B2.1.15-1

Background

In the program description of LRA Section B2.1.15, it describes that the Emergency Diesel Generator (EDG) Storage Tanks and the Technical Support Center (TSC) Diesel Generator (DG) Storage Tank will be periodically drained, cleaned and inspected and the bottom plate will receive an ultrasonic test to determine the minimum wall thickness. The LRA further describes that this program manages aging for underground diesel generator fuel oil storage tanks.

Issue

LRA Section B2.1.15 does not describe the activities that will be performed for the EDG Day Tanks and the TSC DG Day Tank. It is not clear to the staff if the Work Control Process program, which has been credited aging management of the respective day tanks, will perform the activities of draining, cleaning and inspections of the internal surfaces of these day tanks, consistent with the recommendations of GALL Report AMP XI.M30.

Request

Please clarify if the Work Control Process program will periodically drain, clean and visually inspect the interior of the tank and perform an ultrasonic test of the bottom plate to determine minimum wall thickness for the EDG Day Tanks and the TSC DG Day Tank, consistent with the recommendations of GALL Report AMP XI.M30.

- *If yes, clarify and justify the frequency that these activities will be performed.*
- *If not, please clarify the activities that will be performed as part of the Work Control Process program and justify the ability of these activities to provide aging management of the EDG Day Tanks and the TSC DG Day Tank. Please consider the recommendations of GALL AMP XI.M30 to periodically drain, clean and visually inspect the interior of the tank and perform an ultrasonic test of the bottom plate in the justification.*
- *Also, please clarify how there is assurance that the internal surfaces of the day tanks is adequate if some type of inspection is not performed to assess the condition of the tank interior. Including the tank bottom where contamination, water and particulates are likely to settle and accumulate that can lead to loss of material.*

DEK Response

The Work Control Process Program will be used to confirm the effectiveness the Fuel Oil Chemistry Program in managing the loss of material for the internal surfaces of the Emergency Diesel Generator (EDG) Day Tanks and the Technical Support Center Diesel Generator (TSC DG) Day Tank. To ensure the effects of aging are being adequately managed through the period of extended operation, the Work Control Process Program will provide for a one-time inspection of the EDG and TSC DG Day Tanks. An exterior surfaces UT inspection will be performed to verify wall thickness of the bottom of each day tank. Based upon the UT inspections, the most limiting EDG day tank will also be drained, cleaned and visually inspected as a leading indicator for the remaining tanks. However, if material loss is detected by the UT inspection that may affect the intended function of the other day tanks, then the affected day tanks will also be drained, cleaned, and inspected.

An EDG Day Tank will be used for internal visual inspection because the sample points have a riser three inches from the bottom of the tanks. The EDG Day Tanks have been in operation nearly ten years longer than the TSC DG Day Tank. The TSC DG Day Tank provides for a true bottom sample, so there is less chance for buildup of sediment in the bottom of that tank. In addition, the TSC DG Day Tank does not have a man-way to allow for the internal cleaning and inspection.

The one-time inspections will be performed prior to the period of extended operation. The results of the inspection will be used to determine if any additional inspections and/or preventive measures are required during the period of extended operation.

The following commitment will be added to LRA Appendix A, USAR Supplement, Table A6.0-1:

Item	Commitment	Source	Schedule
31	The Work Control Process Program will be enhanced to provide for a one-time-inspection of the Emergency Diesel Generators (EDG) Day Tanks and the Technical Support Center Diesel Generator (TSC DG) Day Tank. An exterior surfaces UT inspection will be performed to verify wall thickness of the bottom of each day tank. Based upon the UT inspections, the most limiting EDG day tank will also be drained, cleaned and visually inspected as a leading indicator for the remaining tanks.	Work Control Process	Prior to the Period of Extended Operation

LRA AMP B2.1.18, Metal Enclosed Bus

RAI B2.1.18-1

Background

In the LRA Sections B2.1.18 and A2.1.18, the applicant implies to inspect only sections of inscope metal enclosed bus (MEBs) using visual inspection. The GALL Report AMP XI.E4 under program description states that, "The purpose of the aging management program is to provide an inspection of MEBs. In this aging management program, bolted connections at sample sections of the buses in the MEBs will be checked for loose connections.

Issue

GALL Report AMP XI.E4 recommends inspecting all MEBs and a sample of bus connections. The applicant AMP implies inspection of only a sample of MEBs.

Request

Please clarify that LRA AMP B2.1.18 inspection of MEBs includes all MEB and a sample of MEB bus connections consistent with GALL Report AMP XI.E4.

DEK Response

Consistent with NUREG-1801, XI.E4, "*Metal Enclosed Bus,*" the Metal Enclosed Bus Program described in LRA Appendix B, Section B2.1.18, includes the inspection of all in-scope metal enclosed buses (MEB). As a clarification, the scope of the MEB inspection described in LRA Appendix A, USAR Supplement, Section A2.1.18, will be revised to replace the third paragraph in the Program Description with the following:

> "The program performs visual inspections of the in-scope MEB for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion, and performs visual inspections of component insulation for surface anomalies, such as discoloration, cracking, chipping or surface contamination.
>
> The program performs visual inspections of a sample of accessible MEB bolted connections that are covered with heat shrink tape, sleeving, insulated boots, etc., for surface anomalies, such as discoloration, cracking, chipping or surface contamination."

The frequency of the MEB and bolted connection inspections described in LRA Appendix A, USAR Supplement, Section A2.1.18 will also be clarified by replacing the fourth paragraph in the Program Description with the following:

> "The inspection of all MEB will be completed prior to the period of extended operation and will be repeated every ten years thereafter.

The inspection of the sample of bolted connections will be completed prior to the period of extended operation and will be repeated every five years thereafter."

Additionally, the frequency of the MEB and bolted connection inspections described in LRA Table A6.0-1, "License Renewal Commitments," Item #13 will be revised by replacing the statement, "Thereafter, the inspections will not exceed a 5-year interval," with the following:

"Thereafter, the inspection of all MEB will not exceed a 10-year interval and the inspection of the sample of bolted connections will not exceed a 5-year interval".

RAI B2.1.18-2

Background

In LRA Section B2.1.18, under the program description, the applicant states that the metal enclosed bus program is supported by the structures monitoring program which performs visual inspection of portions of the MEB enclosure assemblies.

Issue

The staff reviewed the applicant's structural monitoring program and noted that it does not address the visual inspection of MEB.

Request

Describe acceptance criteria of how the structure monitoring program will be used to visually inspect the exterior portions of the MEB consistent with GALL Report Table VI, Item VI.A-12 and VI.A-13.

DEK Response

As indicated in LRA Table A6.0-1, License Renewal Commitments, Item 22, the Structures Monitoring Program will be enhanced to clearly define structures, structural elements, and miscellaneous structural commodities that are in scope. The defined scope includes the Metal Enclosed Bus (MEB) enclosure assemblies, structural supports, and enclosure seals.

As enhanced, the Structures Monitoring Program supports inspections of the MEB, consistent with NUREG-1801, Report Table VI, Item VI.A-12 and VI.A-13, by requiring visual inspections of portions of the MEB enclosure assemblies.

The acceptance criteria for how the Structures Monitoring Program will be used to visually inspect the exterior portions of the MEB are based on the Maintenance Rule Inspection Guideline for Buildings and Structures. Accordingly, the results of the field walkdown performed during implementation of the Structures Monitoring Program verify the effectiveness of maintenance through condition monitoring where the building/structure is classified as (1) Acceptable, (2) Acceptable With Deficiencies, or (3) Unacceptable. The associated guidance for classifying the structures is provided below.

(1) Acceptable - Acceptable structures are capable of performing their structural functions, including the protection and support of maintenance rule systems or components. Acceptable structures are free of deficiencies or degradation which could lead to a possible failure.

(2) Acceptable With Deficiencies - Structures which are acceptable with deficiencies are those capable of performing their structural functions, including the protection, or support of, maintenance rule systems or components, but are degraded or have deficiencies which could deteriorate to an unacceptable condition, if not analyzed or corrected prior to the next scheduled examination.

(3) Unacceptable - Unacceptable structures are those which are damaged or degraded such that they are not capable of performing their structural functions. An unacceptable structure should be classified as a functional failure in accordance with the maintenance rule.

RAI B2.1.18-3

Background

In LRA Section B2.1.18, the applicant states that the existing inspection program is designed to maintain the tightness of metal-enclosed bus joints and joints were torque checked for proper tightness. Re-torque is not recommended in EPRI document TR-104213 (See Sections 7.2.1 and Section 8.2) for electrical bolted connection maintenance. The EPRI document states that "the bolts should not be re-torqued unless the joint requires service or the bolts are clearly loose.

Issue

Verifying the torque is not recommended in EPRI TR-104213. The torque required to turn the fastener in the tightening direction (restart torque) is not a good indicator of the preload once the fastener is in service. Due to relaxation of the parts of the joint, the final loads are likely to be lower than the installed loads.

Request

Provide technical justification of how re-torque procedures at KPS are consistent with industry recommendations.

DEK Response

EPRI TR-104213, *"Bolted Joint Maintenance & Application Guide,"* specifies that bolts should not be re-torqued unless the joint requires service or the bolts are clearly loose.

However, when bolted connections are made accessible, current plant procedures incorrectly specify performance of a torque check on the bolted joints and re-torque of the joint if the as-found torque value is less than the manufacturer's required torque value.

This discrepancy was documented in the Corrective Action Program to determine the necessary revisions to the procedures to provide consistency with the EPRI guidance.

LRA AMP B2.1.19, Non-EQ Electrical Cables and Connections

RAI B2.1.19-1

Background

In LRA Section B2.1.19, the applicant states that an adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for electrical cables and connections. The applicant also states that should an adverse localized environment be observed, a representation sample of electrical cables and connections installed within that environment will be visually inspected for aging.

Issue

The applicant has not established the criteria of how an adverse localized environment is identified. As defined in NUREG 1801, an adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified and analyzed service environment for cables (power, control, and instrumentation) and connections. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

Request

Please describe how adverse localized environments will be established and incorporated into the above AMP.

DEK Response

For structures other than Containment, the normal operating temperature ranges between 60°F and 120°F. One exception is the Auxiliary Feedwater Pump Room in the Turbine Building that has a maximum operating temperature of 139°F. For cumulative exposure, the plant 40 year radiation dose ranges between <1E4 rads and 1.8E7 rads.

The electrical cable and connection insulation material types installed in the plant have been reviewed based on the 60-year service limiting temperature range, which varies between 141°F and 273°F, and the 60-year service limiting radiation dose range, which varies between <1.5E4 rads and 2.7E7 rads (1.5 X 40-year value). Consideration of the temperature rise due to ohmic heating was considered in the review. The results of the review concluded that the installed electrical cable and connection insulation material types do not experience a temperature or radiation environment greater than the 60-year service limiting temperature or radiation ranges. Additionally, there are no installed cables or connections with PVC insulation, which has a 60-year service limiting temperature of 112°F.

The most common adverse localized environments are those created by elevated temperature. Steam generators, feedwater heaters, main steam valves, un-insulated or unshielded hot process piping, steam or packing leaks, high-powered incandescent lighting, motor exhaust air vents, areas with equipment that operate at high temperature, areas with inadequate ventilation, etc., are sources of an adverse localized environment. Electrical cables and connections normally within three feet of these sources may be subject to an adverse localized environment.

Adverse localized environments will be identified through plant operational experience reviews, communication with maintenance, operations, and radiation protection personnel, and the use of environmental surveys. The identified adverse localized environments will be used as an input to the walkdowns performed in support of the *Non-EQ Cables and Connections* Program described in LRA Appendix B, Section B2.1.19.

LRA AMP B2.1.20, Non-EQ Electrical Cable Connections

RAI B2.1.20-1

Background

Section B2.1.20 states that AMP B2.1.20 is consistent with the recommendations of NUREG-1801, Section XI.E6, Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Revised)."

Issue

LRA Section B2.1.20 and the associated USAR supplement (A2.1.20) are not consistent with the GALL Report AMP XI.E6 or NUREG -1801, Vol. 2 Revision 1. However, LRA Section B2.1.20 is representative of the summary description and program elements of staff ISG (ISGLR- ISG-2007-02) issued for public comment by letter dated August 29, 2007 (ADAMS ML072420437). Justification has not been provided as to the acceptability of the changes with respect to GALL AMP XI.E6.

Request

Provide justification that demonstrates that the incorporation of ISG-LR-ISG-2007 into LRA AMP B2.1.20 is consistent with GALL Report AMP XI.E6 program elements and should not be considered an exception or a plant-specific program to GALL Report AMP XI.E6.

DEK Response

The description of the Non-EQ Electrical Cable Connections Program in LRA Appendix B, Section B2.1.20 is supplemented to include the exceptions described below. Each exception indicates the program element affected. A common justification applicable to all the exceptions is included at the end of this response.

Exceptions

1. The program will be a one-time inspection program which will be performed prior to the period of extended operation but not repeated every ten years. The program element affected is "Detection of aging effects".
2. The program will not include high voltage connections. The program elements affected are "Scope of Program," and "Parameters Monitored/Inspected."
3. The program will not include connections that are on the internal side of an active component. The program element affected is "Scope of Program."

Justification

NUREG-1801, Section XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," describes an aging management program for electrical cable connections. An NRC and industry effort is in progress, working towards the issuance of a revision to NUREG-1801, XI.E6, via the Interim Staff Guidance (ISG) process. The latest draft revision of this ISG was presented for public comment in the September 6, 2007, Vol. 72, No. 172 issue of the Federal Register as: Proposed License Renewal Interim Staff Guidance LR-ISG-2007-02: Changes to Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," Solicitation of Public Comment. [72FR51256]

The above exceptions are justified because the Non-EQ Electrical Cable Connections Program is consistent with NUREG-1801 Section XI.E6, as modified by the September 6, 2007 draft revision of LR-ISG-2007-02.

LRA AMP B2.1.21, Non-EQ Inaccessible Medium-Voltage Cables

RAI-B2.1.21-1

Background

For LRA AMP B2.1.21, Program Element 4 the applicant states that inspection for water collection should be performed prior to the period of extended operation and every two years thereafter.

Issue

GALL Report AMP XI.E3 states that the inspection for water collection should be based on actual plant experience with water accumulation in the manhole with an inspection frequency of at least every two years. The staff is concerned that the applicant did not provide plant-specific operating experience to justify the fixed two year inspection frequency. In addition, the staff is concerned that the applicant's program does not provide for adjustment of the two year inspection frequency based on the possibility of subsequent significant water accumulation resulting in cable submergence.

Request

Provide justification for the fixed two-year inspection interval and lack of inspection frequency adjustment should cable submergence occur.

DEK Response

As a clarification, the inspection interval of the in-scope manhole east of the tertiary auxiliary transformer will be performed at least every two years after the initial inspection performed prior to the period of extended operation. LRA Appendix A, USAR Supplement, Section A2.1.21, "Non-EQ Inaccessible Medium-Voltage Cables," will be revised to replace the fifth paragraph in the Program Description with the following:

> "Inspection of the in-scope manhole east of the tertiary auxiliary transformer for water collection will be performed prior to the period of extended operation, and the inspection will be repeated at least every two years thereafter."

If significant water collection is observed during the inspections which may cause the in-scope cables to become submerged, the condition will be documented in the Corrective Action Program. The Corrective Action Program will evaluate the apparent cause and determine required corrective actions, including adjustment of the two year inspection frequency as necessary.

LRA AMP B2.1.23, Open-Cycle Cooling Water System

RAI B2.1.23-1

Background

The applicant states that its proposed aging management program Open Cycle Cooling Water System (B2.1.23) LRA AMP) is consistent with the aging management program Open Cycle Cooling Water System (XI.M20) (GALL AMP) contained in the GALL Report. Section 2 (Preventive Actions) of the GALL AMP states that all service water piping should be lined. The LRA AMP indicates that much of the service water piping is not lined.

Issue

Loss of material due to corrosion can be expected to occur much more rapidly in bare steel and cast iron piping than in lined piping. The absence of linings may require an aging management program which exceeds the requirements established by the GALL AMP.

Request

Please demonstrate that the proposed program is sufficiently robust to adequately manage aging in the absence of pipe.

DEK Response

NUREG-1801, Section XI.M20, "Open Cycle Cooling Water System," Program Element 2 (Preventive Actions) states the Open-Cycle Cooling Water System should be, ".... constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from being exposed to aggressive cooling water environments." The Kewaunee cooling water is taken from Lake Michigan, which is fresh water and relatively free of chemicals and minerals and is, therefore, not considered to be an aggressive cooling water environment.

The Open-Cycle Cooling Water System Program described in LRA Appendix B, Section B2.1.23, includes visual inspections of exposed system piping and components any time the system is opened for maintenance or repair. The program implementing procedures require inspections to identify and document conditions that could cause flow restriction (e.g., silt, sand, mud, fish, rocks, zebra mussels, nodules, tubercules, etc). Unsatisfactory conditions, as defined by the procedures, are documented in the Corrective Action Program for evaluation of the cause of the condition and implementation of necessary corrective actions.

The program also includes activities to maintain the integrity of the open-cycle cooling water systems through a combination of periodic replacement of susceptible dead leg piping and routine ultrasonic examination of select piping segments. The examination results are reviewed by Engineering to evaluate the structural integrity of the piping and to determine the need for piping replacements. If the examinations do not meet the criteria established in the implementing procedure, the condition is documented in the Corrective Action Program.

RAI B2.1.23-2

Background

The applicant states that its proposed aging management program Open Cycle Cooling Water System (B2.1.23) (LRA AMP) is consistent with the aging management program Open Cycle Cooling Water System (XI.M20) (GALL AMP) contained in the GALL Report. Section 2 (Preventive Actions) of the GALL AMP states that chemical treatment is necessary to control biofouling in the open cycle cooling water system.

Issue

Plant operating experience indicates that the biocide injection system is less than fully reliable. Plant operating experience also indicates that zebra mussels are commonly found in various parts of the open cycle cooling water system. Given these observations, it is not clear to the staff that the proposed program is sufficiently robust to adequately manage biofouling during the period of extended operation.

Request

Please either demonstrate the sufficiency of the proposed program to address biofouling (including the reliability of the chemical injection equipment) or propose modifications to the program which will adequately manage aging.

DEK Response

The historically poor availability/reliability of the installed chlorine (biocide) injection system has been recognized and documented in the Corrective Action Program. In response to the Corrective Action Program evaluation, the Chemistry Department developed and implemented a performance indicator for chlorine system unavailability. Trending of this performance indicator clearly shows improving performance since inception in early 2007 (approximately 40% availability) to present (approximately 93% availability).

Although the chlorine injection system has experienced varying degrees of unavailability, zebra mussel treatments have been successfully performed, as needed, without exception. This practice has been shown to be effective for zebra mussel control as evidenced by the routine finding that no live mussels are found during open-cycle cooling water system inspections. The discovery of any mussels or mussel fragments requires notification of the Chemistry Department so appropriate changes to chlorination practices can be implemented.

The corrective actions that have been implemented to improve availability of the chlorine injection system and the results of the zebra mussel treatments demonstrate the effectiveness of the Open Cycle Cooling Water System Program to control the impact of biofouling on the function of open cycle cooling water systems.

RAI B2.1.23-3

Background

The applicant states that its proposed aging management program Open Cycle Cooling Water System (B2.1.23) (LRA AMP) is consistent with the GALL AMP contained in the GALL Report. During its review of operating experience the staff identified numerous instances in which the LRA AMP failed to prevent loss of function. The subjects of some of these operating experience reports dealt with fouling under low flow conditions. The staff was not able to determine the applicant's response to all of these events.

Issue

The applicant demonstrates in the LRA AMP that operating experience obtained from a given component is used to modify the inspection of other similar components/environments. The staff independently identified and reviewed operating experience for which it was not obvious that the operating experience from one component had been applied to other similar components. This was particularly true for low flow heat exchangers.

Request

Please provide additional examples, particularly associated with low flow heat exchangers, demonstrating that operating experience from one component is used to modify the inspection program for other, similar, components.

DEK Response

The following examples of operating experience from one component that was used to modify the inspection program activities for another component are provided:

<u>Safety Injection Pump Lube Oil Cooler Fouling</u>

Visual inspections of the safety injection pump lube oil coolers in January 2004 revealed silt and lakeweed accumulation at the tube pass inlets. Evaluation of this condition determined that low service water flow and small diameter tubing combined to cause the accumulation. Corrective actions included installation of helicoil type heat exchangers with larger diameter tubing.

The extent of condition evaluation considered the susceptibility of other safety related heat exchangers to fouling of this type. Three additional heat exchangers were selected for visual inspection to gather additional information. The evaluation concluded that there were no other safety related heat exchangers that were susceptible to this type of fouling.

An assessment of the effectiveness of the zebra mussel control program was also performed. The assessment resulted in adding a second continuous zebra mussel treatment each year and a requirement to provide the results of all heat exchanger visual inspection reports to the Chemistry Department for review and trending to determine if changes to the zebra mussel control program are needed.

Component Cooling Heat Exchanger Tube Pit Sizing

During the fall 2006 refueling outage, two tubes were removed from one Component Cooling heat exchanger for use in destructive analysis to obtain sizing data on internal diameter pits in the tubing. The purpose of this analysis was to aid in flaw sizing for future inspections, since the size of internal diameter pits affect the through-wall estimation via eddy current testing.

Lab testing results showed that the eddy current flaw sizing technique used at the time could under-estimate the depth of a pit. Comparing the pit size analysis to the results of the eddy current testing performed during the fall 2006 refueling outage determined that the eddy current sizing was non-conservative.

The results of the eddy current testing performed during the fall 2006 outage were re-evaluated using the new pitting size information. It was determined that the re-evaluated tube pitting did not degrade the performance of the heat exchangers, nor did it challenge the overall structural integrity of the tube or the heat exchanger. In addition, the revised technique used for sizing internal diameter pits was subsequently applied to all heat exchangers subject to eddy current testing.

LRA AMP B2.1.24, Primary Water Chemistry

RAI B2.1.24-1

<u>*Background*</u>

GALL AMP XI.M2 ("Water Chemistry") states that it is based on the primary water chemistry guidelines for pressurized water reactors contained in EPRI Report TR-105714 ("Pressurized Water Reactor Primary Water Chemistry Guidelines, Rev. 3") published in 1995, or later revisions. The applicant's LRA Section B2.1.24 ("Primary Water Chemistry") states that its Primary Water Chemistry AMP is based upon EPRI Report 1002884, which it identifies as "Pressurized Water Reactor Primary Water Chemistry Guidelines, Vol. 1, Rev. 6."

<u>*Issue*</u>

EPRI Report 1002884 cited by the applicant is actually Revision 5 of "Pressurized Water Reactor Primary Water Chemistry Guidelines, Vol. 1," issued in October 2003. Revision 6 of this report, which is the most recent revision (published in December 2007) is EPRI Report 1014986 and is the edition of the report currently in effect.

<u>*Request*</u>

Clarify which revision of the EPRI report "Pressurized Water Reactor Primary Water Chemistry Guidelines, Vol. 1" forms the basis for the applicant's Primary Water Chemistry AMP B.1.24.

DEK Response

The EPRI document that should have been referenced in LRA Appendix B, Section B2.1.24 is EPRI 1014986, *"Pressurized Water Reactor Primary Water Chemistry Guidelines,"* Revision 6.

RAI B2.1.24-2

<u>Background</u>

EPRI Report 1014986 ("Pressurized Water Reactor Primary Water Chemistry Guidelines, Vol. 1, Rev. 6"), which forms the most recently updated basis for GALL AMP XI.M2 ("Water Chemistry"), defines action level limits for dissolved oxygen in the primary water for operation under reactor critical conditions (Table 3-3). These limits are >5 ppb for Action Level 1, >100 ppb for Action Level 2, and >1000 ppb for Action Level 3.

<u>Issue</u>

The applicant's Primary Water Chemistry Program Directive (NAD-01.44, Rev D) defines action level limits for dissolved oxygen for reactor critical conditions that are identical to those contained in EPRI Report 1014986. However, the applicant's Primary Chemistry Sample Specifications Procedure (CY-KW-040-001, Rev. 2) defines the following action levels for the same conditions: Action Level 1: >5 ppb, Action Level 2: (no limit stated), and Action Level 3: >100 ppb.

<u>Request</u>

Resolve this apparent inconsistency between the applicant documents NAD-01.44, Rev D and CY-KW-040-001, Rev. 2.

DEK Response

Procedure CY-KW-040-001, "*Primary Chemistry Sample Specifications*," Revision 2, has been reviewed and it was determined that the action level limits for dissolved oxygen for reactor critical conditions require updating to be consistent with EPRI Report 1014986, "*Pressurized Water Reactor Primary Water Chemistry Guidelines,*" Revision 6. This condition has been documented in the Corrective Action Program in order to address this discrepancy.

RAI B2.1.24-3

Background

EPRI Report 1014986 ("Pressurized Water Reactor Primary Water Chemistry Guidelines, Vol. 1, Rev. 6"), which forms the most recently updated basis for GALL AMP XI.M2 ("Water Chemistry"), states on p. B-13 that the concentration limit for reactive silica in the boric acid storage tanks is 5000 ppb. It further states that this limit is for 4% boric acid, and that the limit can be increased proportionally for higher boric acid concentrations.

Issue

The applicant's Primary Water Chemistry Program Directive (NAD-01.44, Rev D) states on p. 12 that, for the boric acid storage tank, the limit on reactive silica is 5,000 ppb. However, the applicant's Chemistry Procedure (CY-KW-040-001, Rev. 2) states on p. 13 that the limit on reactive silica is 10,000 ppb. In footnote 2 for this latter value, the applicant notes that the EPRI limit of 5,000 ppb has been increased proportionally for the higher boric acid level of approximately 8%, as permitted by the EPRI guidance. The limits on reactive silica in the two applicant documents appear to be inconsistent.

Request

Resolve this apparent inconsistency between the applicant documents NAD-01.44, Rev. D and CY-KW-040-001, Rev. 2.

DEK Response

Administrative Procedure NAD-01.44, "*Kewaunee Primary Water Chemistry Program,*" Revision D does not specifically address the limit on reactive silica for the Boric Acid Storage Tank. However, Nuclear Fleet Administrative Procedure CY-AP-PRI-100, "*Primary Water Chemistry,*" (page 12), Table 9 (*Boric Acid Storage Tank Chemistry Suggested Parameters*) states that the reactive silica suggested limit should be ≤5,000 ppb. Footnote 2 of the table applying to reactive silica states that the "Limit is for 4% boric acid. Limit can be increased proportionately for higher percentage boric acid concentrations." This stated limit and the associated footnote are taken directly from EPRI Report 1014986, "*Pressurized Water Reactor Primary Water Chemistry Guidelines,*" Volume 1, Revision 6.

The site-specific chemistry procedure is CY-KW-040-001, "*Primary Chemistry Sample Specifications,*" Revision 2, Step 5.9, "*Boric Acid Storage Tank Chemistry Suggested Parameters,*" (page 13) provides a suggested reactive silica limit of ≤10,000 ppb. Note 2 of the table applying to reactive silica states: "EPRI limit is for 4% boric acid. Limit has been increased proportionally for higher percentage boric acid concentrations (about 8%)."

Since the limits in both procedures are proportionally equivalent, as per the EPRI Guidelines, there is no discrepancy between the procedures.

RAI B2.1.24-4

<u>*Background*</u>

The applicant's LRA lists a number of structures and components for which the operating environment is primary water and for which aging is managed by the Water Chemistry Program (e.g., IV.B2-2, IV.C2-13, IV.D1-4, etc.). GALL states that no further aging management review is necessary for these and similar components if the applicant provides certain component-specific commitments in the FSAR Supplement.

<u>*Issue*</u>

The applicant's USAR Supplement A2.1.24 for the Primary Water Chemistry Program includes no commitments with respect to the components described above.

<u>*Request*</u>

Revise USAR Supplement A2.1.24 to include the appropriate commitments for the component types described above or provide a justification for not including these commitments.

DEK Response

These FSAR Supplement commitments referred to in the request are identified in NUREG-1801, "*Generic Aging Lessons Learned (GALL) Report*," Volume 2, Chapter IV, "Reactor Vessel, Internals, and Reactor Coolant System" tables, along with the NUREG-1801, Section XI.M2, "Water Chemistry" program. There are two such commitments in these tables applicable to Kewaunee; (1) management of cracking for nickel-alloy components, and (2) management of degradation of reactor vessel internals (RVI) components.

These commitments are not associated with the LRA Appendix B, Section B2.1.24, "Primary Water Chemistry Program." Rather, the commitments are encompassed by the plant-specific Alloy 600 Inspections Program (described in LRA Appendix B, Section B2.1.1) for nickel-alloy cracking, and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (described in LRA Appendix B, Section B2.1.2) for Reactor Vessel Internals (RVI) issues. The management of RVI degradation issues involves following industry development of aging management methods as described in LRA Appendix A, Table A6.0-1, "License Renewal Commitments," Item 1. Thus no USAR Supplement changes are required.

LRA AMP B2.1.30, Steam Generator Tube Integrity

RAI B2.1.30-1

Background

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

Issue

KPS program document, Technical Report KLR-1319, describes the steam generator tube integrity aging management program. The aging management program has numerous references. Several of the references have been superseded (e.g., references 8.8 and 8.9), and some are no longer the current versions of the document (e.g., reference 8.12).

Request

Please discuss your plans for modifying the document to be consistent with the updated references and provide the list of references.

DEK Response

Following development and submittal of the LRA, the Kewaunee Steam Generator Program was transitioned to the Dominion Fleet Steam Generator Program and several of the program reference documents were revised or superseded. A review of KLR-1319, "*Steam Generator Tube Integrity*," supporting LRA Appendix B, Section B2.1.30, has been performed and the document has been updated to reflect the revised references. The revised list of references, as reflected in KLR-1319, is as follows:

8.0 REFERENCES

8.1 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," Code of Federal Regulations, U.S. Nuclear Regulatory Commission, Washington, D.C.

8.2 NUREG-1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report," U.S. Nuclear Regulatory Commission, September 2005.

8.3 Dominion Nuclear Fleet Administrative Procedure ER-AP-SGP-10, "Steam Generator Program Description."

8.4 Technical Specifications for Kewaunee Power Station, Sections 6.9 and 6.22.

8.5 NEI 97-06, Revision 2, "Steam Generator Program Guidelines," Nuclear Energy Institute, May 2005.

8.6 Letter from Clark R. Steinhardt, Senior Vice President Nuclear Power – Wisconsin Public Service Corporation to U.S. Nuclear Regulatory Commission – Document Control Desk, "NRC Generic Letter 97-06: Degradation of Steam Generator Internals (GL 97-06)," March 30, 1998.

8.7 Letter from Tae Kim, Senior Project Manager, Section 1 – Plant Directorate III – Division of Licensing Project Management – Office of Nuclear Reactor Regulation, to M. L. Marchi, Site Vice President - Kewaunee Plant, "Kewaunee Nuclear Power Plant – Closeout of Generic Letter 97-06, Degradation of Steam Generator Internals (TAC NO. MA0921)," November 4, 1999.

8.8 Dominion Nuclear Fleet Administrative Procedure ER-AP-SGP-101, "Steam Generator Program."

8.9 Dominion Nuclear Fleet Administrative Procedure ER-AP-SGP-102, "Steam Generator Degradation Assessment."

8.10 Dominion Nuclear Fleet Administrative Procedure ER-AP-SGP-103, "Steam Generator Condition Monitoring and Operational Assessment."

8.11 KPS General Nuclear Procedure GNP-01.21.05, "Steam Generator Primary Channel head Closeout Inspection."

8.12 Dominion Nuclear Administrative Procedure MA-AA-102, "Foreign Material Exclusion."

8.13 EPRI PWR Steam Generator Examination Guidelines.

8.14 KPS Steam Generator Secondary Side Integrity Plan.

8.15 Letter from David H. Jaffe, Senior Project Manager – Plant Licensing Branch III-1 – Division of Operating Reactor Licensing – Office of Nuclear Reactor Regulation, to David A. Christian, Senior Vice President and Chief Nuclear Officer, "Kewaunee Power Station – NRC Generic Letter 2006-01: Steam Generator Tube Integrity and Associated Technical Specifications (TAC NO. MD0085)," ADAMS Accession NO: ML062480050, September 22, 2006.

8.16 Letter from David H. Jaffe, Senior Project Manager – Plant Licensing Branch III-1 – Division of Operating Reactor Licensing – Office of Nuclear Reactor Regulation, to David A. Christian, Senior Vice President and Chief Nuclear Officer, "Kewaunee Power Station – Issuance of Amendment RE: Steam Generator Tube Integrity (TAC NO. MC9581)," ADAMS Accession NO: ML061700208, ML061700091, ML061720131, July 17, 2006.

8.17 Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," August 1976.

8.18 KPS General Nuclear Procedure GNP-01.21.04, "Primary-to-Secondary Leak Monitoring Program."

8.19 KPS Surveillance Procedure SP-36-084, "Steam Generator Tube Inspection."

8.20 EPRI Steam Generator Integrity Assessment Guidelines.

8.21 Topical Report DOM-QA-1, "Dominion Nuclear Facility Quality Assurance Program Description."

8.22 Nuclear Fleet Administrative Procedure PI-KW-200, "Corrective Action."

8.23 KPS Nuclear Administrative Directive NAD-03.01, "Directive, Implementing Document, and Procedure Control."

8.24 KPS General Nuclear Procedure GNP-03.01.01, "Directive, Implementing Document, and Procedure Administrative Controls."

8.25 Dominion Nuclear Administrative Procedure DNAP-0501, "Dominion Nuclear Procedure Administrative Control Program."

8.26 Nuclear Fleet Program Description AD-AA-10, "Administrative Controls Program."

8.27 Nuclear Fleet Guidance and Reference Document PI-AA-100-1007, "Operating Experience Program."

8.28 KPS Nuclear Engineering Procedure NEP-14.13, "Operating Experience Procedure."

8.29 Technical Specification Task Force, Improved Standard Technical Specifications Change Traveler, Steam Generator Tube Integrity (TSTF-449), Revision 4, May 6, 2005 (70 FR 24126).

8.30 NRC Generic Letter 2006-01, "Steam Generator Tube Integrity And Associated Technical Specifications," dated January 20, 2006.

8.31 NEI Correspondence "Revision 2 to NEI 97-06 Steam Generator Program Guidelines," dated September 9, 2005.

RAI B2.1.30-2

Background

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

Issue

KPS program document, SP-36-084, "Steam Generator Tube Inspection," Revision 0, dated August 17, 2006, does not appear to be updated to reflect the latest version of the Electric Power Research Institute (EPRI) "Pressurized Water Reactor Steam Generator Examination Guidelines." Nuclear Energy Institute (NEI) initiative NEI 97-06, "Steam Generator Program Guidelines, Revision 2," which is referenced as an acceptable aging management program for steam generator tube integrity in the GALL report, requires licensees to modify their Steam Generator Programs upon issuance of updated guidelines during the time frame specified in the letter forwarding the revised guidelines. In addition, Kewaunee procedures appear to require the issuance of a corrective action system entry to ensure that the appropriate procedures have been updated. The staff also notes that a similar issue was previously identified during a Kewaunee self-assessment and an external review visit in 2005.

Request

Please confirm whether SP-36-084 has been updated to reflect the latest version of the EPRI guidelines. Provide your plan to ensure that future updates to the guidelines will be incorporated in a timely manner.

DEK Response

Surveillance procedure SP-36-084, "Steam Generator Tube Inspection," Revision 0, dated August 17, 2006, has been reviewed, and it was determined that the procedure has not been appropriately updated to the latest version (Revision 7) of the EPRI Guidelines as identified during the NRC review. The need to update SP-36-084 has been documented in the Corrective Action Program to ensure that the procedure is revised in a timely manner.

To ensure future updates are incorporated in a timely manner, SP-36-084 will also be revised to reference fleet program document ER-AP-SGP-101, "Steam Generator Program," which implements the latest version of the EPRI Pressurized Water Reactor Steam Generator Examination Guidelines. ER-AP-SGP-101 contains the requirements to ensure that Kewaunee Steam Generator Program document revisions are implemented within the time frame specified in the transmittal letter forwarding the revised industry guidelines.

RAI B2.1.30-3

Background

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

Issue

During the review of KPS program document, SP-36-084, the staff identified several potential discrepancies between the industry guidelines (referenced in NEI 97-06) and the plant procedure.

Request

Please address the following issues:

- *In section 1.3 in the "Validation of Inspection Intervals" section, there is a note indicating that the first inservice inspection of the steam generators can not occur within six effective full power months of steam generator replacement. This statement appears to be in conflict with the requirements in NEI 97-06 (and the steam generator technical specifications) which do not specify a minimum timeframe limit on when the first inservice inspection shall be (other than during the first refueling outage following replacement).*
- *In section 2 in the "Validation of Inspection Intervals" section, it appears that the inspection frequencies for the steam generators may exceed the requirements of NEI 97-06 if both steam generators are not inspected every outage. Please confirm that the guidance in this procedure is sufficient to ensure the inspection frequency of NEI 97-06 (and the technical specifications) will not be exceeded. If it isn't sufficient, discuss your plans to modify the procedure.*
- *In the "Categorization of Steam Generator Tube Inspection Results" section, there are references to the inspection categories and degraded and defective tubes. This terminology appears to have been replaced in the latest version of the EPRI Steam Generator Examination Guidelines. Please discuss.*
- *In the "Condition Monitoring Screening" section, paragraph 5.2.2, implies that growth rates need to be assessed as part of condition monitoring. The evaluation of growth rates is not relevant for condition monitoring. Please clarify. In addition, the reason for not assessing all indications in condition monitoring (regardless of depth) is not clear.*

- *In the "Loose Parts Disposition Flow Chart," there does not appear to be an option that the safety evaluation of a loose part could result in a conclusion that is unacceptable to leave the part/tube in service.*

DEK Response

The issues identified in RAI B2.1.30-3 have been documented in the Corrective Action Program and the following changes are being implemented in the next revision of surveillance procedure SP-36-084, "Steam Generator Tube Inspection:"

- The note in section 1.3 of the "Validation of Inspection Intervals" section is being removed, which eliminates the conflict with NEI 97-06 and the steam generator Technical Specification 6.22.d.1.
- A new note is being added to the "Validation of Inspection Intervals" section to clarify requirements should both steam generators not be inspected every outage.
- The definitions for degraded and defective tubes are being revised to be consistent with Revision 7 of the EPRI Pressurized Water Reactor Steam Generator Examination Guidelines.
- Section 5.2.2 in the Condition Monitoring Screening section is being revised to clarify that growth rates are used in the operational assessment. Section 5.2 is also being revised to ensure that all indications, regardless of depth are assessed.
- The Loose Parts Disposition Flow chart is being revised to better define the process subsequent to the safety evaluation for foreign material which has been determined to be irretrievable and that could cause damage. The revised flow chart provides clear guidance for plugging defective tubes and performing an assessment on the need to stabilize defective tubes and adjacent tubes when the loose part cannot be removed.

RAI B2.1.30-4

Background

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

Issue

The regulatory requirements section (3.1.9) in KPS program document, ER-AP-SGP-101, "Steam Generator Program," does not appear to list all of the regulatory requirements identified in NEI 97-06.

Request

Please address this inconsistency.

DEK Response

ER-AP-SGP-101, "Steam Generator Program," Section 3.1.9 was not intended to include a complete listing of regulatory requirements identified in NEI 97-06, Rev. 2, "*Steam Generator Program Guidelines.*" As a clarification to ER-AP-SGP-101, the documents listed in Section 3.1.9 have been relocated to the references section of the procedure.

RAI B2.1.30-5

Background

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

Issue

- *Section 3.1.3 of ER-AP-SGP-102, "Steam Generator Degradation Assessment," requires compliance with the latest revision of the EPRI guidelines; however section 3.1.6 of ER-AP-SGP-101 requires compliance with the latest revision of the EPRI guidelines within the timeframe in the transmittal letter for the new guidelines.*
- *Section 3.2.1.d of ER-AP-SGP-102 appears to try to ensure tube integrity for the operating interval between inspections; however, it is not clear that this is possible to do such an assessment prior to the inspection (since the actual inspection results are needed for the assessment of tube integrity for the next operating interval).*

Request

Please resolve these apparent conflicts.

DEK Response

Kewaunee program document, ER-AP-SGP-102, "Steam Generator Degradation Assessment," has been updated. Section 3.1.3 was clarified to require compliance with the latest revision of the EPRI guidelines within the timeframe in the transmittal letter for the new guidelines.

EPRI Steam Generator Integrity Assessment Guidelines, Revision 2, Section 3.4 states:

> "The repair limit is the NDE measured parameter at or beyond which the tube is to be repaired or removed from service by plugging. **The repair limit shall be established prior to the inspection** *{emphasis added}* and tubes exceeding this limit during the inspection shall be repaired. The repair limit is defined such that the performance criteria will be met at the end of the inspection interval. If a Technical Specification repair limit is defined, the more limiting value shall be used."

Section 3.2.1.d of ER-AP-SGP-102 implements this requirement.

RAI B2.1.30-6

Background

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

Issue

Section 3.2.5 of ER-AP-SGP-102 on insitu pressure testing only addresses differential pressure loads.

Request

Since NEI 97-06 requires the assessment of loads other than that associated with differential pressure, please discuss whether Section 3.2.5 is sufficient for verifying tube integrity. If it is not sufficient, please discuss your plans for modifying this section to reflect all the loads that must be considered per NEI 97-06 (and the technical specifications).

DEK Response

ER-AP-SGP-102, "Steam Generator Degradation Assessment," provides guidance for the development of the Degradation Assessment report and does not provide final test pressures to be used to perform steam generator tube in-situ testing. Section 3.2.5 of this procedure documents the pre-determined test pressure inputs related to normal and design-basis accident primary-to-secondary pressure differentials since these can be determined in advance of steam generator inspections. In the event that in-situ pressure testing is determined to be required, the guidance contained in ER-AP-SGP-101, "Steam Generator Program," would be followed to determine the in-situ test pressure and other parameters. ER-AP-SGP-101, Section 3.1.1, requires compliance with NEI 97-06, "*Steam Generator Program Guidelines*," Rev. 2, and the EPRI Steam Generator In-Situ Pressure Test Guidelines. ER-AP-SGP-101, Section 3.2.1, includes the structural integrity performance criterion contained in NEI 97-06 which addresses assessment of applicable loads.

As a clarification, Section 3.2.5 of ER-AP-SGP-102 has been revised to state that in-situ pressure testing is performed in accordance with the EPRI Steam Generator In-Situ Pressure Test Guidelines.

RAI B2.1.30-7

Background

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

Issue

Section 3.2.2 of ER-AP-SGP-103 implies that growth rates need to be assessed as part of condition monitoring. The evaluation of growth rates is not relevant for condition monitoring. Section 3.2 of ER-AP-SGP-103 requires an assessment of the accident induced leakage performance criteria; however, this document does not indicate the probability and confidence level for this assessment. The probability and confidence level for the structural integrity assessment is provided in the document, and is consistent with NEI 97-06.

Request

Please resolve these discrepancies.

DEK Response

It is the intent of ER-AP-SGP-103, "Condition Monitoring and Operational Assessment," Section 3.2.2 to meet the following requirement from the EPRI Steam Generator Integrity Assessment Guidelines, Section 7.6, which states:

> "If, upon completion of the CM evaluation, which may include in situ pressure testing, the results indicate that structural and/or leakage integrity evaluations fail to satisfy any of the performance criteria, the condition shall be reported to the NRC and Industry in accordance with the reporting requirements of the plant's Technical Specifications and NEI 97-06. Failure to meet the CM criteria indicates that the conclusions of the prior operational assessment were incorrect. Therefore, causal analysis shall be completed and necessary corrective actions shall be identified and, if appropriate, be implemented prior to MODE 4. Some examples of appropriate corrective actions include: lowering the repair limit to account for unexpectedly high degradation growth rates; ..."

Therefore, consistent with the EPRI Guidelines, growth rates are assessed as part of condition monitoring to determine if lowering the repair limit may be required.

Kewaunee complies with the probability and confidence levels for the performance criteria specified in NEI 97-06 in accordance with ER-AP-SGP-101, "Steam Generator Program," Section 3.2.2. As a clarification, ER-AP-SGP-103 has been revised to add the probability and confidence level for the accident induced leakage performance criteria.

RAI B2.1.30-8

<u>*Background*</u>

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

<u>*Issue*</u>

Section 2.0 of ER-AP-SGP-103, "Condition Monitoring and Operational Assessment," indicates that condition monitoring is required whenever steam generators are being inspected.

<u>*Request*</u>

Since NEI 97-06 and the technical specifications require condition monitoring to be performed when inspections are performed or tubes are plugged, please discuss whether this procedure is also applicable when steam generator tubes are plugged (without inspection).

DEK Response

ER-AP-SGP-103, "Condition Monitoring and Operational Assessment," has been revised to include the applicability of the procedure when steam generator tubes are plugged.

RAI B2.1.30-9

Background

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

Issue

Section 3.2.5 of ER-AP-SGP-103 appears to only require an assessment of accident induced leakage when operational leakage is observed.

Request

Given that there may be accident induced leakage without observing operational leakage, discuss how your program ensures the NEI 97-06 accident induced leakage criteria will be met.

DEK Response

ER-AP-SGP-103, "Condition Monitoring and Operational Assessment," has been revised to clarify that accident induced leakage requires an assessment even if no operational leakage is observed.

RAI B2.1.30-10

Background

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

Issue

Section 3.2.11 of ER-AP-SGP-103 provides various conditions when the differential pressure across the steam generator tubes must be assessed and included in the operational assessment.

Request

Since there may be other conditions that result in an increase in the differential pressure across the tubes (e.g., fouling), please discuss why only those conditions identified in the procedure as increasing the differential pressure across the tubes are required to be assessed.

DEK Response

EPRI Steam Generator Integrity Assessment Guidelines, Section 2.2, states:

> "Changes in design parameters such as plugging or sleeving levels, primary or secondary side modifications, or T_{hot} shall be assessed and included if they result in primary to secondary pressure differences that are greater than the values used in the evaluation of SIPC by more than 50 psi."

The intent of ER-AP-SGP-103, "Condition Monitoring and Operational Assessment," Section 3.2.11 was to address this EPRI requirement. A revision to ER-AP-SGP-103 relocates this information to ER-AP-SGP-101, "Steam Generator Program," along with a clarification that there may be other conditions resulting in increased differential pressure across the tubes requiring an operational assessment.

RAI B2.1.30-11

Background

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

Issue

The Secondary Side Integrity Plan apparently references several outdated references.

Request

Please address this discrepancy and specify your plans for updating this document.

DEK Response

The Secondary Side Integrity Plan has been reviewed and it was determined that the Plan references outdated documents as identified during NRC review. This condition has been documented in the Corrective Action Program to ensure that the Secondary Side Integrity Plan references are updated during the next revision of the Plan.

RAI B2.1.30-12

<u>Background</u>

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

<u>Issue</u>

Section 6.3 of the steam generator Secondary Side Integrity Plan makes "recommendations" on sludge lancing. Since this document is the plan for performing secondary side inspections, it is not clear that these "recommendations" are consistent with the requirements of section 3.3.6 or ER-AP-SGP-101 which requires a plan.

<u>Request</u>

Please address this discrepancy.

DEK Response

The Steam Generator Secondary Side Integrity Plan has been reviewed for consistency with ER-AP-SGP-101, "Steam Generator Program," Section 3.6.6, "Maintenance of Steam Generator Secondary Side Integrity," which provides guidance for development of a secondary-side maintenance strategy for long-term steam generator operability and performance. As identified during the NRC review, the Steam Generator Secondary Side Integrity Plan, in Section 6.3, provides recommendations for steam generator sludge-lancing based on a review of past steam generator maintenance results and industry, fleet, and plant-specific operating experience. These recommendations are an input to the Secondary Side Cleaning Plan included as Attachment E to the Steam Generator Secondary Side Integrity Plan. The Secondary Side Cleaning Plan provides a plan for steam generator maintenance activities during future refueling outages, including sludge-lancing.

As a result of this review, the Steam Generator Secondary Side Integrity Plan has been determined to be consistent with Section 3.6.6 of ER-AP-SGP-101.

RAI B2.1.30-13

Background

The applicant stated in Section B2.1.30 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity," with exceptions. It further stated that its program meets the intent of NEI 97-06 as recommended by NUREG-1801.

Issue

Two documents, ER-AP-SGP-10, Steam Generator Program Description, Revision 1 and Dominion Nuclear Fleet Program Description ER-AP-SGP-101, Steam Generator Program, Revision 2, describe the responsibilities of steam generator program personnel. The staff noted some inconsistencies in the designation and responsibilities defined for Steam Generator Program. For example, in Section 4.2 of ER-AP-SGP-10, Administrative information- Responsibilities, the applicant stated that it is the "Manager Corporate Engineering Programs – Innsbrook" who is responsible for designating the Fleet Lead for the SG program. However, in Section 5.2.3 of ER-AP-SGP-101, Administrative information-Responsibilities, the applicant stated that it is the "Director Nuclear Engineering – Innsbrook - Programs" who is responsible for designating a Fleet Lead for the Steam Generator program. Also, Section 4.2.2 of ER-APSGP- 10 states that "Manager Nuclear Engineering – Site" is responsible for implementing the site SG program while Sections 5.2.2 and 5.2.11 of ER-AP-SGP-101 indicate otherwise. These discrepancies could create some misunderstandings about the responsibilities of people in charge of implementing the Steam Generator Tube Integrity AMP.

Request

Please review these documents and clarify the responsibilities of each person involved in Steam Generator Program are identified correctly and consistently. Confirm that these updates are performed.

DEK Response

ER-AP-SGP-10, "Steam Generator Program Description," and ER-AP-SGP-101, "Steam Generator Program," have been reviewed, and revised where necessary, to clarify the responsibilities of each person involved in Steam Generator Program. Additionally, all fleet Steam Generator Program procedures have been reviewed, and revised as necessary, to ensure responsibilities are identified consistently.

LRA AMP B2.1.31, Structures Monitoring Program

RAI B.2.1.31-1

Background

LRA Section B2.1.31 states that applicant's "Structures Monitoring Program" is an existing program that corresponds to NUREG-1801, Section XI.S5, "Masonry Wall Program," XI.S6, "Structures Monitoring Program," and XI.7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants".

Issue

LRA Section A does not clearly describe the program summary with all necessary references for implementation as defined in NUREG-1800, Rev. 1.

Request

Revise Appendix A, "Program Description" to summarize AMP B2.1.31 consistent with the level of details provided in NUREG-1800, Rev. 1.

DEK Response

LRA Appendix A, USAR Supplement, Section A2.1.31, "Structures Monitoring Program," will be revised to add the following statement to the end of the third paragraph in the Program Description:

> "The program implements the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," with the guidance of NUMARC 93-01, Revision 2, *"Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*," and Regulatory Guide 1.160, Revision 2, "*Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*.""

RAI B.2.1.31-2

Background

LRA Section B2.1.31 states that the Structures Monitoring Program is an existing program and is consistent with the recommendations of NUREG 1801. Technical Report KLR: 1431 – "Structures Monitoring Program" Attachment 5 presents an element by element evaluation of the applicant's program with the corresponding GALL Report Program.

Issue

The technical report does not clearly describe the program elements with all necessary references for implementation as defined in the GALL Report Program elements.

Request

Include all the references for implementation in the element by element comparison to be consistent with the GALL Report or explain why they are not included.

DEK Response

A review of the program elements for the Structures Monitoring Program provided in Technical Report KLR-1341 found that the references required for implementation were not complete for 3 of the 10 elements. Consequently, a change has been initiated to include the references specified below in the indicated element during the next update of the Structures Monitoring Program:

Program Element: 3 – Parameters Monitored/Inspected

ACI 349.3R-96 and ANSI/ASCE 11-90

Program Element: 4 - Detection of Aging Effects

ACI 349.3R-96, ANSI/ASCE 11-90 and RG 1.127

Program Element: 10 - Operating Experience

NRC IN 87-67

RAI B.2.1.31-3

Background

The LRA Section B2.1.31 states that the "Structures Monitoring Program" will be enhanced to monitor ground water quality and verify that it remains non-aggressive to below-grade concrete.

Issue

Evidence of apparent high chloride and sulfate was noted in Section 3.5.2.2.1.1 of the LRA and also in reviewed condition report CR095754.

Requests

- *Describe past and present groundwater monitoring activities at the Kewaunee Power Station, including the results for sulfates, pH and chlorides.*
- *Provide the location(s) where test samples were/are taken relative to the safety-related and important-to-safety embedded concrete foundations.*
- *Indicate seasonal variations.*
- *Explain the technical basis and acceptance criteria.*

DEK Response

Past and Present Groundwater Monitoring

Groundwater samples taken during plant construction in July 1968 and June 1971 indicated a pH range of 7.40 to 7.90, a chloride range of 14.8 to 39.0 ppm and a single reading for sulfates of 359.40 ppm. Groundwater readings from the Independent Spent Fuel Storage Installation (ISFSI) monitoring wells taken between February 2006 and December 2006 indicated a pH range of 7.40 to 8.48, a chloride range of 2.21 to 18.30 ppm and a sulfate range of 40.74 to 118.6 ppm. As indicated, these natural groundwater readings around the site are well within the limits established in NUREG 1801 for a non-aggressive environment (i.e., pH > 5.5, chlorides < 500 ppm, and sulfates < 1500 ppm).

Based on the requirements established in NUREG-1801 for inaccessible concrete areas, groundwater samples have recently been obtained in the immediate area of the plant structures (tritium assessment wells installed in 2007). Groundwater samples taken in the June 2007; March, July, August, and October 2008; and March and June 2009 indicate a pH range of 7.10 to 8.17, a chloride range of 34 to 1240 ppm and sulfate range of 36 to 422 ppm. The recently obtained values for the pH and sulfates do not vary significantly from the previous values and are in all cases, well within the limits established in NUREG-1801 for a non-aggressive groundwater environment.

Some of the recently obtained groundwater well samples have slightly higher chlorides that exceed the conservative limit of 500 ppm. The average chloride readings from the eight wells selected for monitoring for license renewal are: 267 ppm, 268 ppm, 120 ppm, 530 ppm, 518 ppm, 366 ppm, 640 ppm, and 169 ppm. A condition report was submitted to document the chloride readings exceeding the conservative limit of 500 ppm. In an attempt to reduce the ground water chloride content as much as possible, corrective action included an investigation to determine if application of the current deicer product could be modified or if an alternate deicer product could be used.

Sample Locations Relative to Plant Structures

The location of the tritium assessment wells, selected for license renewal due to their location respective to plant structures, is primarily along the centerline of the site and in the immediate area of the Shield Building, Auxiliary Building, Turbine Building, and the Technical Support Center and the adjacent paved area. The location of these wells is in the proximity of safety related and important-to-safety embedded concrete foundations.

Seasonal Variations

As indicated above, groundwater samples have been taken in each of the four seasons. The groundwater sample results do not vary significantly from season to season.

Technical Basis and Acceptance Criteria

The slightly elevated chloride levels were obtained from three wells located in the proximity of paved plant areas that are heavily salted for deicing purposes during the winter months. Consequently, salt is the most likely contributor to the elevated chloride concentrations found in the groundwater samples from these wells. Research has indicated that the use of salt, instead of sand, as a deicer for the paved areas began sometime between 1992 and 2000. Therefore, the concrete has only been exposed to elevated chloride levels for a limited time.

The limit of 500 ppm for chloride levels was established as a very conservative value at which an investigation would be initiated to determine the cause of the higher levels and, if possible, an attempt would be made to reduce the level. Experience has shown that long-term continued exposure of concrete to atmospheric conditions combined with seawater (chloride level of approximately 19,000 ppm) may cause some degradation of rebar, resulting in cracking and spalling of portions of the concrete. As indicated above, 640 ppm is the highest average chloride level to which the concrete at Kewaunee has been exposed. This condition is less severe than the environment for concrete exposed to seawater and therefore, the integrity of the inaccessible concrete near these wells is not a concern.

The inaccessible below grade concrete at Kewaunee is constructed to ACI standards which affords a dense concrete with low permeability and provides for adequate concrete cover of the rebar on the exterior surfaces. As a good engineering practice, a water proofing membrane (40 mils thick) was installed during initial construction of the below grade concrete of the plant structures. The waterproofing membrane consists of a continuous plain sheet of polyvinyl chloride applied to the concrete surface with an adhesive and minimizes any direct contact between the concrete structures and the groundwater environment.

As indicated in LRA Appendix B, Section B2.1.31, inaccessible concrete will be monitored by the Structures Monitoring Program. The monitoring of inaccessible concrete will include the following:

1. Examination of the exposed portions of the below-grade concrete, when excavated for any reason, and;
2. Periodic monitoring of below-grade water chemistry, including consideration of potential seasonal variations.

Based on the dense and good quality concrete originally installed at Kewaunee, combined with the adequate concrete cover, and the fact that the average chloride readings at three wells is only marginally above the conservative value of 500 ppm, the potential for any degradation due to current levels of chloride in the groundwater is not considered to be a concern.

RAI B.2.1.31-4

Background

The LRA Appendix B "Operating Experience" section states leaching and cracking was observed on the outer concrete surface of the reactor refueling cavity wall. Based on inspection and chemistry sampling, a small amount of borated water found its way down the wall, followed the crack, and deposited boric acid when it was dried.

Issue

The last inspection was performed in October 2004. There is no discussion of managing and/or preventing further degradation in the LRA.

Request

- *Provide further information on what has been done to monitor the cracking, leaching, and leakage of boric acid after the last inspection in 2004.*
- *What action will be taken to manage the degradation during the period of extended operation to prevent any loss of intended function?*
- *Address the adequacy of the current inspection interval considering the specific operating experience.*

DEK Response

The crack location on the south side of the outer concrete surface of the reactor refueling cavity wall was first discovered in April 2003 and a follow-up inspection was scheduled to be performed during the 2004 refueling outage. In October 2004, with the refueling pool flooded, the crack location was re-inspected and it was concluded that there was no active leak from any source going through the crack. Based on the inspection results, it was additionally concluded that no further action was required.

During the fall 2006 refueling outage, regularly scheduled Boric Acid Corrosion Program inspections were performed and no leakage was reported at the suspect location. During the spring 2008 refueling outage, regularly scheduled Structures Monitoring Program inspections did not identify any noticeable boric acid at the crack location.

For this area, the regularly scheduled Structures Monitoring Program inspections will continue to be performed and general area inspections inside the containment will be performed every refueling outage, as part of the Boric Acid Corrosion Program, to look for signs of boric acid.

Based on the above specific operating experience, the current inspection interval for the Structures Monitoring Program is effective and adequate. During the period of extended operation, if the Structures Monitoring Program inspection results indicate the presence of degradation, an increased inspection frequency will be implemented to ensure that the intended functions of the affected structure are maintained.

It is noted that there were other leak locations identified on the outer concrete surface of the reactor refueling cavity wall during the 2006 and 2008 refueling outages by the Structures Monitoring Program and the Boric Acid Corrosion Program. These are discussed in RAI B2.1.3-1.

RAI B.2.1.31-5

Background

During the audit, while reviewing condition reports, it was found that a white substance was observed on the wall and ceiling of the waste drumming room, below the spent fuel pool. The issue was discovered in December 2007. According to the condition report (CR), it is boric acid related.

Issue

The white substance indicates leakage of borated water through the concrete, which may be degrading the concrete and rebar.

Request

- *Provide the information regarding the source of the leakage and any plan to fix the leakage prior to entering the period of extended operation.*
- *If no plan exists to fix the leakage, provide the monitoring plan, inspection methods, and inspection schedule to ensure that aging degradation will be detected and quantified before there is loss of intended functions.*

DEK Response

The white substance observed on the wall and ceiling of the waste drumming room, below the spent fuel pool, was first discovered on December 28, 2007. Subsequently, several meetings were held with Chemistry, Radiological Protection, Engineering, and Operations personnel to discuss spent fuel pool makeup, housekeeping/contamination, groundwater concerns, and the potential for structural degradation. The area was cleaned, continuing observations and troubleshooting were performed to determine the cause of the condition, and a corrective action plan was established.

Inspection and evaluation by structural engineering before and after cleaning determined that the structural integrity of the concrete was not adversely affected and the structure was sound. This conclusion was based on the fact that concrete did not display visible spalling (which would indicate that the reinforcing is corroding and causing pop outs of the concrete), deformed surfaces (which would indicate that the reinforcement is in distress), or widening of cracks. Additionally, rebar in reinforced concrete is normally protected against corrosion by the alkalinity of the concrete, which is typically in the range of pH 12.5 or more, and promotes a protective passive layer on the steel.

A little more than a month after the area was cleaned, the residue was again observed on the ceiling, but no active dripping was noted. In June 2008, it was decided that the immediate future follow-up actions would be limited to monitoring and troubleshooting, as applicable. A recurring activity was added to the work control system that required monthly visual inspection and photography of the leak location. The photos are being maintained for comparative analysis.

At this time, periodic cleaning of the leak site is not being performed because it would provide little additional data or information, while subsequently increasing site dose and workload. Instead of periodic cleaning, deposits at the leak sites are being monitored for changes in size, shape and color. In addition, the leak site can be monitored to determine the effect of draining the fuel transfer canal, such as during fuel transfer system maintenance, on leakage indications.

The wall and ceiling of the waste drumming room has been monitored for approximately one year and the observations have confirmed that the boric acid residue formation has remained constant. Based on the slow formation rate (months), there is no near term concern for the integrity of the structure or potential loss of intended function. Leakage monitoring will continue to be performed in the future. Further evaluation and additional corrective actions will be considered if any changes in the leakage trend or other signs of concrete distress are observed.

RAI B.2.1.31-6

Background

During the LRA audit, a plant walkdown was performed. Various concrete degradation mechanisms were observed on the walls of the Screenhouse Structures. The noted deficiencies/aging effects include cracking, leaching, and patterned cracking. According to the operating experience presented in Section B2.1.31, the last inspection was done in April 2008.

Issue

Several evidences of leaching were observed. According to the operating experience presented in Appendix B, the last inspection was done in April 2008 and this structure will be included in the long-range rehabilitation plan. Also the applicant stated that this structure was "Acceptable with Deficiency".

Request

Staff requests an explanation of the long-range rehabilitation plan. What actions will be taken to manage the concrete aging effect and maintain integrity of the structure during the period of extended operation?

DEK Response

The Operating Experience discussion in LRA Appendix B, Section B2.1.31, incorrectly indicated that the status of the Screenhouse structure following the April 2008 inspection was "acceptable with deficiencies" and that the Screenhouse structure would be included in the long-range rehabilitation plan. The status of the Screenhouse structure as a result of the April 2008 inspections should have been identified as "acceptable."

Currently, inspection results for the Screenhouse walls indicate that small hairline cracking has occurred with some leaching. There has been no indication of spalling of the concrete, which would indicate corrosion of the reinforcing.

Structures Monitoring Program inspections of the Screenhouse structure will continue during the period of extended operation to ensure there is no loss of structure or structural component intended function and that the structural integrity of the Screenhouse is maintained. Additionally, the circulating water pump room wall will be inspected during each refueling outage to manage concrete aging. As necessary, deficiencies noted during the Structural Monitoring Program inspections will be entered into the Corrective Action Program, evaluated, and, if required, repairs or additional corrective action initiated.

The actions that will be taken to manage the concrete aging and to maintain integrity of the Screenhouse structure during the period of extended operation will ensure that there is no loss of structure or structural component intended function.

LRA TLAA Support Programs

TLAA/AMP B3.2, Metal Fatigue of Reactor Coolant Pressure Boundary

RAI B3.2-1

Background
In LRA Section B3.2, the applicant states that the KPS Metal Fatigue of Reactor Coolant Pressure Boundary program monitors and tracks the critical thermal and pressure transients to ensure that cycle occurrence limits are not exceeded so that the ASME Class 1 vessels and pressurizer surge line fatigue analyses assumptions are maintained.

Issue
In the LRA, there was no description or discussion regarding how KPS has been and will be monitoring the severity of pressure and thermal (P-T) activities during plant operations. It is essential that all thermal and pressure activities (transients) are bounded by the design specifications (including P-T excursion ranges and temperature rates) for an effective and valid aging management program.

Request

- *Describe the procedures that KPS uses for tracking thermal transients.*
- *Confirm that all monitored transient events are bounded by the design specifications.*
- *Specify the time (years) over which actual transient monitoring and cycle tracking activities took place. If there have been periods for which transient events were not monitored since the initial plant startup, specify the affected time frame, and provide justification to demonstrate that the estimated cycles for this unmonitored period are conservative.*
- *Provide a histogram of cycles accrued for plant heatup and plant cooldown transients.*

DEK Response

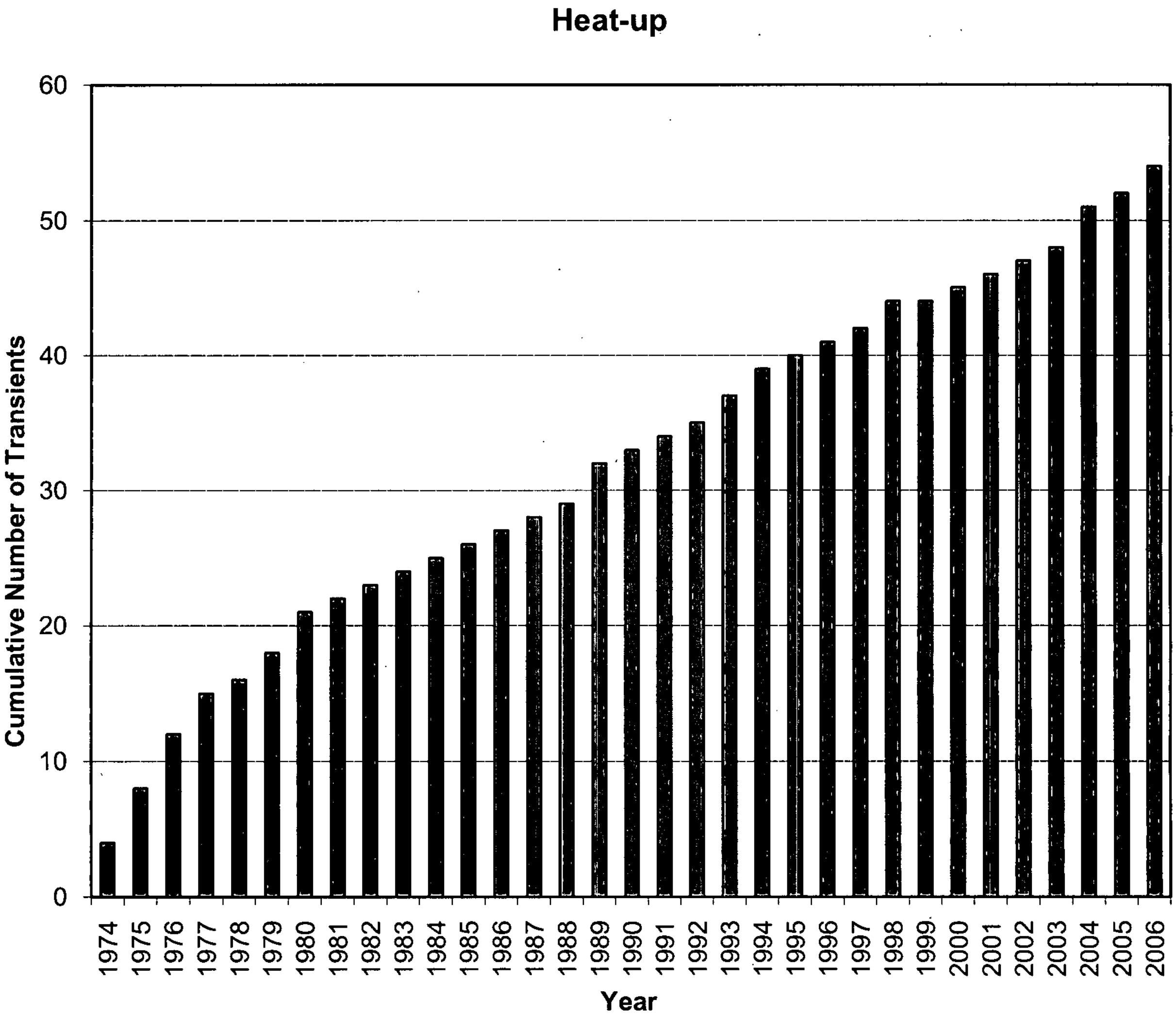
The significant thermal and pressure transients used as input to the ASME Code Section III stress analyses for Class 1 components are defined in the associated design specifications and described in USAR Section 4.1.5. Each transient is also listed in USAR Table 4.1-8 along with the limit for the number of occurrences for each transient. The limit for the numbers of transient occurrences is the same value as the number of transients assumed in the fatigue evaluations performed as part of the Class 1 component stress analyses. LRA Table 4.3-1 provides the same list of transients and limits, along with the number of occurrences accumulated to-date and a projection of the number of occurrences of the transient to the end of the period of extended operation. As described in USAR Section 4.1.5, transient conditions were defined for fatigue evaluation based on a conservative estimate of the magnitude and frequency of the temperature and pressure cycles resulting from normal operation, normal and abnormal load transients, and accident conditions.

The thermal and pressure transients listed in USAR Table 4.1-8 are tracked by the Metal Fatigue of Reactor Coolant Pressure Boundary Program as described in LRA Appendix B, Section B3.2. The requirements of the program are implemented by a plant surveillance procedure. The procedure includes a summary description of critical parameters associated with the transient definition and requires tracking the occurrence of transients listed in USAR Table 4.1-8. If a thermal or pressure transient occurs that is not bounded by the transient parameters described in the procedure, the event is documented in the Corrective Action Program and an engineering evaluation is performed to determine the impact on applicable components and analyses.

Monitoring and tracking plant operational transients through the Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that that the Class 1 components are operated within the fatigue design basis defined by the component design specifications for the life of the plant.

The thermal and pressure transients listed in USAR Table 4.1-8 have been monitored and tracked since initial plant operation in 1973.

Histograms of cycles accrued for plant heatup and plant cooldown transients are shown on the following pages.


Heat-up
Cumulative Number of Transients
0
10
20
30
40
50
60
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986
1987
1988
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2004
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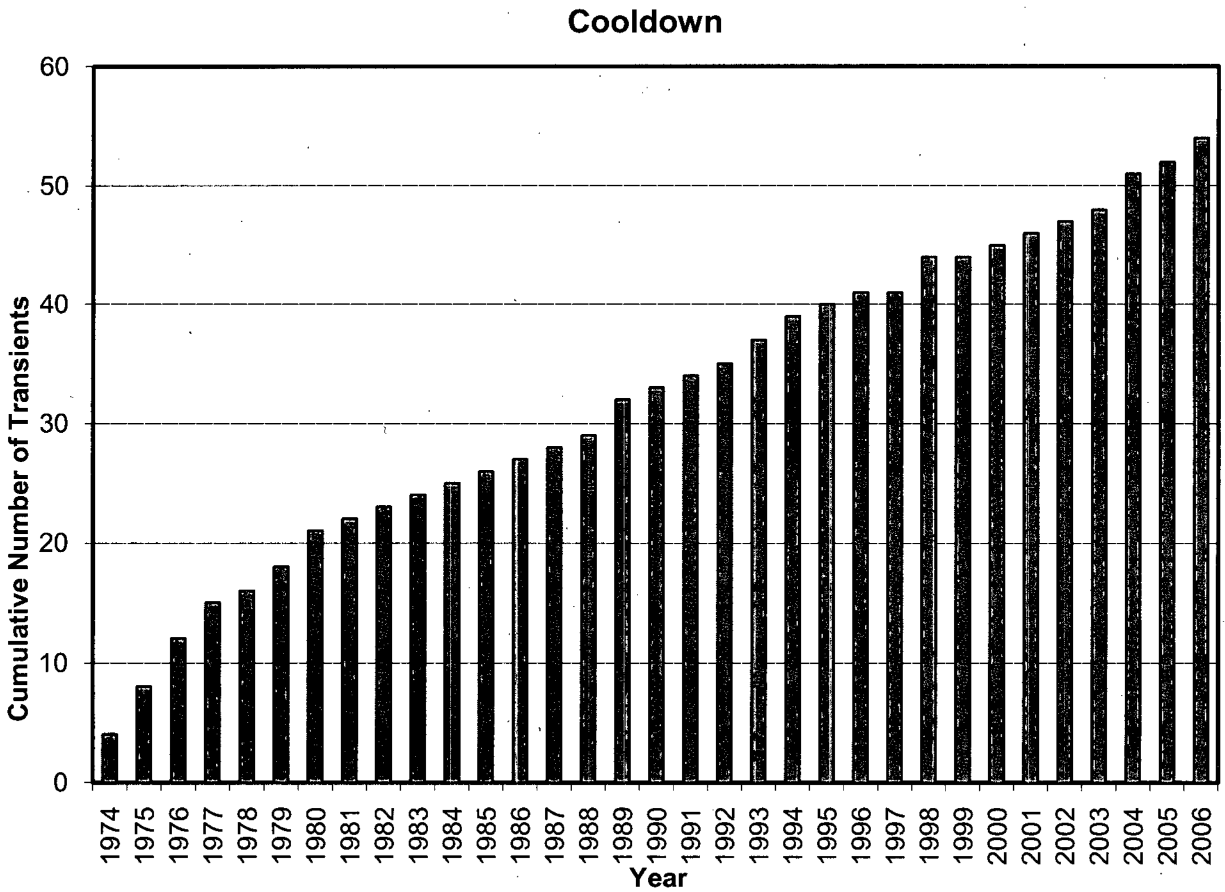
Year


Cooldown
Cumulative Number of Transients
0
10
20
30
40
50
60
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
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2002
2003
2004
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2006
Year

RAI B3.2-2

Background

LRA Section B3.2 states that the KPS Metal Fatigue of Reactor Coolant Pressure Boundary program utilizes all three modules of EPRI software FatiguePro to perform cycle counting, cycle-based fatigue (CBF) monitoring, and stress-based fatigue (SBF) monitoring.

Issue

In its stress-based fatigue monitoring module, FatiguePro does not use all six components of a transient stress tensor (Sxx, Syy, Szz, Sxy, Syz, Szx) to perform fatigue analysis in accordance with the ASME Section III NB-3200 guidance. FatiguePro takes simplified approach by producing only one stress component and uses that single stress component for fatigue usage evaluation. NRC Regulatory Issue Summary (RIS) 2008-30, titled "Fatigue Analysis of Nuclear Power Plant Components," dated December 16, 2008 (ML083450727), requests that the license renewal applicants that have used this simplified methodology perform confirmatory analyses to demonstrate that the simplified analyses provide acceptable results. In addition, there are multiple occurrences of terminologies "stress-based monitoring" and "SBF" in the body of the LRA. If the plant does not have appropriate stress monitoring capability, use of such terminologies would be misleading.

Request

- *Make appropriate adjustments and corrections regarding the use of the "stress-based monitoring" and "SBF" terminologies, and reliance to the SBF methodology for fatigue usage calculations. This action applies to the entire body of the LRA, including License Renewal Commitment 28.*
- *Identify the items whose CUF values were calculated using FatiguePro or simplified methodology, including the results shown in LRA Tables 4.3-2 and the results embedded in the text (not tabulated). The items that are identified must be reevaluated in accordance with the guidelines described in ASME Section III NB-3200, taking all 6 components of stress into consideration.*

DEK Response

The re-analysis of locations subject to evaluation of the environmental effects on fatigue usage in accordance with NUREG/CR-6260, "*Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components*," that were initially evaluated using stress-based fatigue (SBF) monitoring methods, is currently in progress. The response to RAI B3.2-2 will be provided following completion of the re-analysis.

RAI B3.2-3

Background

Under the Operation Experience paragraphs in LRA Section B3.2, the applicant describes a 2001 incident that potentially challenged the charging line and reactor coolant loop piping nozzle fatigue limits. The applicant states that KPS documented the event in the Corrective Action Program and performed a fatigue evaluation for the charging and reactor coolant loop piping as well as for the charging nozzle. In addition, the applicant states that the engineering evaluation determined that no fatigue limits were exceeded based on a review of the USAS B31.1 design code requirements for the charging and reactor coolant loop piping.

Issue

Clarification is required.

Request

Describe the engineering analysis performed for the incidental transient.

DEK Response

The event described under Operating Experience in LRA Appendix B, Section B3.2, "Metal Fatigue of the Reactor Coolant Pressure Boundary," was a letdown flow isolation that occurred with continued charging flow to the reactor coolant loop. This resulted in a thermal transient in the charging line, since without letdown flow there is no pre-heating of charging flow in the regenerative heat exchanger. This event was entered into the Corrective Action Program and the thermal transient was evaluated for its effect on the charging line and reactor coolant loop piping and nozzle.

A qualitative engineering evaluation was performed considering the applicable requirements of the design code of record, USAS B31.1-1967. There is no requirement within this code for a detailed fatigue analysis; however, full range temperature cycles are limited to 7000 occurrences. The evaluation concluded that the charging line and reactor coolant loop piping have not experienced temperature cycles approaching this limit. In addition, the thermal sleeve installed at the nozzle serves to minimize the effect of thermal transients. The result of the evaluation was that there was no adverse affect on piping or nozzle structural integrity due to this event and all design code requirements were met.

RAI B3.2-4

Background

Under the Operation Experience paragraphs in LRA Section B3.2, the applicant describes that unusually high differential temperatures between the pressurizer surge line and RCS hot leg have been mistakenly logged, ΔT.

Issue

KPS attributed the unusually high ΔT to the erroneous use of the 'subcooling' data when the pressurizer is in a water solid condition while heating up or cooling down. According to the description shown in LRA Section B3.2, water solid condition will be formed during the heatup and cooldown process under the 'Modified Steam Bubble' method.

Request

- *Describe the 'Modified Steam Bubble' method, which KPS has been using since the plant startup (as indicated in LRA Section 4.3.1.4).*
- *At what stage of the heatup/cooldown process will water-solid condition be established under the 'Modified Steam Bubble' method?*
- *How KPS determines ΔT now since the mistake has been corrected?*

DEK Response

The 'Modified Steam Bubble' operating method was one of the plant start-up and shutdown methods defined during the Westinghouse Owner's Group (WOG) investigations into pressurizer insurge / outsurge and surge line thermal stratification issues. This operating method provides guidelines to increase pressurizer spray flow and reduce differential temperature between the pressurizer and the reactor coolant loop during plant heat-up and cooldown, thereby reducing the potential metal fatigue effects of pressurizer insurge / outsurge.

This method of operation had been used at Kewaunee for start-up and shutdown since initial plant operation in 1973. As indicated in LRA Section 4.3.1.4, operating procedures were changed at the end of cycle 28 (March 2008) to incorporate the 'Water Solid' method of startup and shutdown. The 'Water Solid' operating method provides for greater reduction in system differential temperatures and increased continuous outsurge from the pressurizer during plant heat-up and cooldown, thus further reducing the potential metal fatigue effects of pressurizer insurge / outsurge.

Under the 'Modified Steam Bubble' operating method, water solid conditions were established in the pressurizer at the beginning of the plant heat-up process and maintained until a steam bubble was formed at reactor coolant loop conditions of approximately 200 – 250°F and 400 psig. During the cooldown process, the pressurizer steam bubble was collapsed at reactor coolant conditions of approximately 180°F and 450 psig.

The differential temperature (ΔT) between the pressurizer and the reactor coolant loop is determined through a calculated plant computer data point that subtracts the greater of reactor coolant loop A or loop B wide range temperature from the pressurizer water temperature.

LRA TLAA

TLAA 4.3, Metal Fatigue

RAI 4.3-1

<u>Background</u>

In LRA Section 4.3, the applicant states that if the component has a fatigue time-limited aging analysis (TLAA) that remains valid (i) or is projected to cover the period of extended operation (ii), then cracking due to fatigue is not an aging effect requiring management for those components during the period of extended operation.

<u>Issue</u>

If cracks developed while the TLAA has concluded that the component is qualified for either 10 CFR 54.21(c)(1)(i) or 10 CFR 54.21(c)(1)(ii), then it is most likely because either the TLAA results have been questionable or the pre-operational inspection results and handling of the inspection results have been questionable. Cracking is a major safety issue for any components. Immediate remedial actions must be taken for cracks that are detected at any time.

<u>Request</u>

The statement quoted under the Background above implies that cracking could be ignored as long as the stated conditions are met. Provide the basis to justify this statement and discuss how KPS would handle the situation.

DEK Response

The statement quoted in RAI 4.3-1 from LRA Section 4.3 was not intended to imply that identified cracking in pressure boundary components could be ignored based on the determination that fatigue TLAAs are shown to remain valid for the period of extended operation. All required inspections will continue to be performed for components within the scope of metal fatigue TLAAs and identified non-conforming conditions, including cracking, evaluated in accordance with the Corrective Action Program, as appropriate.

RAI 4.3-2

Background

LRA Section 4.3.1.5 describes the environmental fatigue evaluation and the results are presented in LRA Table 4.3-2, including the Fen values determined for each component or location evaluated.

Issue

LRA Table 4.3-2 shows three Fen values for all of the components evaluated: 2.455 for all of the locations that use low alloy steel (LAS); 15.35 for all of the locations that use stainless steel (SS) except for the RHR Tee at safety injection accumulator line location. It is known that the Fen value depends on material, strain rates, temperature and the dissolved oxygen (DO) concentration of the reactor water. Here, the SS is not in question because 15.35 is the bounding Fen for SS. Fen value of 2.455 for the LAS involves an assumption that DO is no greater than 0.05 ppm.

Request

- *Summarize KPS' experience in control of DO level in the reactor water since the plant startup. Describe all water chemistry programs KPS has used, including procedures and requirements used for managing DO concentration as well as the inception date of each water chemistry program.*
- *Provide a historic summary of the DO level since the plant startup. Estimate the fraction of time of the KPS operating history, thus far, that the DO level exceeded 0.05 ppm.*
- *Describe how reactor water samples were taken, including the sampling locations. If samples were taken from a single location, justify that the DO data discussed in Part (b) above are applicable to all NUREG/CR-6260 components for the Fen calculations.*

DEK Response

The Kewaunee Technical Specifications provide a limit of 100 ppb for dissolved oxygen with the reactor coolant temperature greater than 250°F. This requirement is implemented through the chemistry control program as described in LRA Appendix B, Section B2.1.24, "Primary Chemistry Control." Reactor coolant dissolved oxygen (DO) has been controlled since initial plant operation and is currently controlled in accordance with the latest industry guidelines provided in EPRI 1002884, "*Pressurized Water Reactor Primary Water Chemistry Guidelines*." Reactor coolant chemistry control includes monitoring of water chemistry parameters, including DO concentration, through routine sampling and analysis of the samples for contaminants. The DO concentration in the reactor coolant is controlled by maintaining an elevated hydrogen concentration through hydrogen over-pressure in the volume control tank of the Chemical and Volume Control System that provides Reactor Coolant System (RCS) make-up water.

The reactor coolant elevated hydrogen concentration is effective in mitigating oxidizing conditions due to radiolysis or oxygen ingress. Historically, dissolved oxygen concentrations are significantly less than the limit provided in the Technical Specifications or in the EPRI guidelines. Based on a review of reactor coolant chemistry data from 1984 to 2009, the typical reactor coolant DO concentration during normal operation has been less than 5 ppb (0.005 ppm). Although DO concentrations above 5 ppb were noted in the data, these were typically associated with plant shutdown and start-up when reactor coolant temperatures are low resulting in reduced potential for corrosion due to high DO levels. Based on the review of chemistry data, there have been no significant periods where the reactor coolant system operated at a temperature greater than 250°F and DO concentration was greater than 50 ppb. Based on the DO concentration control method utilized, the sampling frequency and DO concentration limits specified in the chemistry control program, and the historical DO concentrations at Kewaunee, it is reasonable to assume that reactor coolant DO concentration will continue to be maintained below 50 ppb (0.05 ppm) at temperatures above 250°F.

Reactor coolant samples are taken on a routine basis either directly from the sample point at the reactor coolant 'B' hot leg connection during normal operation or indirectly via the Residual Heat Removal system sample point during start-up and shutdown. Based on flowrates through the RCS that promote mixing within the system, the samples obtained are representative of the bulk reactor coolant water chemistry. The low-alloy steel (LAS) locations that are required to be evaluated for the effects of the reactor coolant environment on fatigue usage in NUREG/CR-6260, "*Application of NUREGICR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components*," are the reactor vessel nozzles and reactor vessel shell to lower head transition. There are no stagnant fluid conditions, potentially caused by dead-leg or creviced geometries, at these locations. As such, the local water chemistry at these locations is expected to be consistent with the bulk reactor coolant water chemistry conditions. Therefore, the DO concentration data discussed above are representative of the DO concentration at these locations.

RAI 4.3-3

Background

LRA Section 4.3.2.1 discusses TLAA for Non-Class 1 piping and states that KPS performed a reevaluation for the reactor coolant hot leg sample line to account for the increased number of thermal expansion cycles.

Issue

The information provided in the LRA is insufficient to enable one to perform an independent evaluation.

Request

- *Describe the sampling practice, including number of times sampling activity takes place each day or each week. Estimate total number of thermal cycles projected for 60 years, including those due to the sampling operations and those due to other means.*
- *Provide the maximum stress intensity range induced by those thermal cycles.*
- *Specify the allowable stress range, and the stress range reduction factor used in the reevaluation described in LRA Section 4.3.2.1.*

DEK Response

Reactor coolant hot leg samples are taken seven times per week (i.e., one sample per day) during normal operation. This equates to 21,840 samples in a 60-year period (7 samples/week * 52 weeks/year * 60 years). Conservatively, the analysis of the reactor coolant hot leg sample line assumed 43,680 full temperature cycles to account for non-routine sampling.

In accordance with USAS B31.1-1967, the maximum stress range was determined to be 20,104 psi. The allowable stress range is 26,683 psi using a stress range reduction factor, f, equal to 0.7 corresponding to 22,000 to 45,000 full temperature cycles.

LRA TLAA Support Programs

TLAA/AMP B3.1, Environmental Qualification (EQ) of Electrical Components

RAI-B3.1-1

Background
LRA Section B3.1 and SRP Table 4.4.2 GALL Report AMP X.E1 state that reanalysis for aging evaluation is normally performed to extend the qualification by reducing excess conservatism incorporated in the prior evaluation. Important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met).

Issue
A staff's review of the LRA Section A3.3 (USAR supplement for B3.1) notes that it does not include reanalysis attributes consistent with the program description of LRA Section B3.1 and SRP Table 4.4.2 (10 CFR 54.21(c)(1)(iii)).

Request
Please reconcile LRA Section B3.1 and the LRA Section A3.3 (USAR Supplement descriptions) with SRP LR Table 4.4.2.

DEK Response

To provide consistency with NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Table 4.4-2, Examples of FSAR Supplement for Environmental Qualification of Electric Equipment TLAA Evaluation, the following statement will be added after the first sentence in the third paragraph of LRA Appendix A, USAR Supplement, Section A3.3, "Environmental Qualification of Electric Equipment:"

> "Re-analysis of aging evaluations to extend the qualifications of components is performed on a routine basis as part of the program. Important attributes for the re-analysis of aging evaluations include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met)."

RAI-B3.1-2

Background

GALL Report AMP X.E1, "Parameters Monitored/Inspected," program element states in part that monitoring programs are an acceptable basis to modify a qualified life of electrical components through reanalysis.

Issue

In support of AMP B3.1, Technical Report KLR-1301, Section 4.4, Program Element 3, "Parameters Monitored/Inspected," Section 4.5 Program Element 4, "Detection of Aging Effects," and Program Element 5, "Monitoring and Trending" specifically references ambient temperature monitoring as being used to modify EQ components qualified life. The AMP description is not clear whether temperature monitoring will be continued into the period of extended operation.

Request

Explain how ambient temperature monitoring is or will be performed and controlled under the environmental qualification (EQ) program consistent with GALL Report AMP X.1E and continues to ensure that component qualified life remains bounded with respect to the EQ ambient temperature.

DEK Response

The ambient temperature monitoring data used in the Environmental Qualification (EQ) program is historical data obtained from a monitoring program that was performed during the 1991-1992 timeframe. There is no ambient temperature monitoring currently being performed for the EQ program.

Generally, EQ components qualified life analyses use the plant design temperatures, which are higher, on average, than actual service temperatures. However, when service temperatures are used in the analyses, the historical temperature monitoring data is adjusted to account for plant modifications or changes that could affect ambient temperatures since the temperature monitoring data was obtained. In addition, ambient temperature monitoring data from the warmest months of the year (i.e., summer and fall) are typically used as inputs to the qualification analysis and lower service temperatures due to plant outages or out of service times are typically not taken into account. Consequently, the component qualified life analyses are based on conservative, bounding service temperature inputs with respect to the ambient temperature.