UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

July 7, 2015

Mr. Michael P. Gallagher
Vice President, License Renewal Projects
Exelon Generation Company, LLC
200 Exelon Way
Kennett Square, PA 19348

SUBJECT: REQUESTS FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE LASALLE COUNTY STATION, UNITS 1 AND 2 LICENSE RENEWAL APPLICATION – SET 5 (TAC NOS. MF5347 AND MF5346)

Dear Mr. Gallagher:

By letter dated December 9, 2014, Exelon Generation Company, LLC (Exelon) submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part 54, to renew the operating licenses NPF-11 and NPF-18 for LaSalle County Station (LSCS), Units 1 and 2, respectively. The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing the information contained in the license renewal application and has identified, in the enclosure, areas where additional information is needed to complete the review.

These requests for additional information were discussed with Mr. John Hufnagel, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me at 301-415-3019 or by e-mail at Jeffrey.Mitchell2@nrc.gov.

Sincerely,

/RA/

Jeffrey S. Mitchell, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-373 and 50-374

Enclosure:
As stated

cc: Listserv

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ADAMS Accession Number: **ML15159A208** *Concurred via e-mail

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DATE	6/18/15	6/19/15	6/23/15	7/7/15	7/7/15

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Letter to Michael Gallagher from Jeffrey S. Mitchell dated July 7, 2015

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LASALLE COUNTY STATION, UNITS 1 AND 2
LICENSE RENEWAL APPLICATION
REQUESTS FOR ADDITIONAL INFORMATION – SET 5
(TAC NOS. MF5347 AND MF5346)

RAI 3.3.1.110-1

Background:

License Renewal Application (LRA) Table 3.3.1, Item 3.3.1-110 addresses cracking due to stress corrosion cracking (SCC) of stainless steel piping, piping components, and piping elements in the Auxiliary Systems, which are exposed to treated water greater than 60 °C (140 °F). The Generic Aging Lessons Learned (GALL) Report recommends GALL aging management program (AMP) XI.M7, "BWR Stress Corrosion Cracking," and GALL AMP XI.M2, "Water Chemistry," to manage this aging effect for the components. The GALL Report also indicates that GALL AMP XI.M7 is based on the staff positions described in Generic Letter (GL) 88-01.

LRA Table 3.3.1 indicates that Item 3.3.1-110 is not applicable because the Boiling Water Reactor (BWR) Stress Corrosion Cracking program manages crack initiation and growth in reactor coolant pressure boundary piping, welds and components greater than 4 nominal pipe size (4 NPS). The LRA also indicates that LRA Item 3.3.1-19, in comparison with Item 3.3.1-110, is used to manage cracking of stainless steel piping, piping components, and piping elements which are less than 4 NPS and exposed to treated water greater than 140 °F in the auxiliary systems.

The staff noted that the following reference with its Enclosure 1 indicates that the applicant's BWR Stress Corrosion program, which is based on GL 88-01, includes American Society of Mechanical Engineers (ASME) Code Class 1, 2, and 3 piping made of stainless steel that contains reactor coolant at temperature above 200 °F during power operation.

- Dresden Station Units 2 and 3; Quad Cities Stations Units 1 and 2; LaSalle County Station Units 1 and 2; Response to Generic Letter 88-01; Docket Nos. 50-237/249, 50-245/265, 50-373/374; July 29, 1988 (Agencywide Documents Access and Management System (ADAMS) Accession No. 8808090125)

Tables E-4 and E-5 in Enclosure 1 of the reference also indicate that the applicant's BWR Stress Corrosion Cracking program includes piping welds located in the Reactor Water Cleanup system. The staff further noted that LRA Section 3.3.1 indicates that the Reactor Water Cleanup system is included in the Auxiliary Systems.

Issue:

LRA Item 3.3.1-110 and Table 3.3.2-21 (the aging management review (AMR) table for the Reactor Water Cleanup System) do not identify the piping welds that are included in the applicant's program as described in the reference document above.

Request:

Clarify why LRA Item 3.3.1-110 and Table 3.3.2-21 do not identify the reactor water cleanup system piping welds that are included in the program as described in the reference document above. If these welds are within the scope of the program, add relevant AMR items to manage cracking due to SCC for these components.

RAI B.2.1.10-1

Background:

GALL Report AMP XI.M17, "Flow-Accelerated Corrosion," as modified by LR-ISG-2012-01, "Wall Thinning Due to Erosion Mechanisms," states that the program relies on implementation of NSAC-202L, "Recommendations for an Effective Flow-Accelerated Program," Revision 2 or Revision 3. LRA Section B.2.1.10 states that the LaSalle County Station, Units 1 and 2 (LSCS) Flow-Accelerated Corrosion program is based on NSAC-202L, Revision 3. However, during the AMP Audit, it was disclosed that, after the submission of the LRA, the program was being revised to incorporate the guidance in NSAC-202L, Revision 4. The staff noted that NSAC-202L, Revision 4 was issued by the Electric Power Research Institute (EPRI) in November 2013, and this revision has not been previously considered in a license renewal safety evaluation.

Issue*:*

1. Since the applicant is using NSAC-202L, Revision 4, the LRA AMP is no longer consistent with the GALL Report AMP as originally stated in the LRA. Therefore, the applicant needs to demonstrate that the LRA AMP will ensure that the effects of aging in the impacted systems, structures and components will be adequately managed to prevent the loss of intended function.
2. For the trace chromium content exclusion, NSAC 202L, Revision 3 had previously included discussions about trace chromium content; however, the exclusion only applied after initial inspections confirmed that wear was not occurring. NSAC-202L, Revision 4 now incorporates an exclusion from evaluation for similar trace amounts of chromium without these initial inspections by stating, "Experience has shown…." EPRI report 1008047, "Flow-Accelerated Corrosion Investigations of Trace Chromium," was published in 2003, but it is not clear to the staff what bases support the experience aspect being cited in NSAC-202L, Revision 4 to justify the change.

Request:

1. As a result of LSCS's recent change to the implementation guidance for the Flow-Accelerated Corrosion program from that described in the LRA, if the LRA program will continue to be based on the GALL Report AMP, provide an explanation of the exception to the GALL Report AMP and the necessary program element changes to justify why the program, with exception, will be adequate to manage the effects of aging. Include a discussion of any technical changes that are incorporated in NSAC-202L, Revision 4, as they relate to each program element.

2. For the trace chromium system evaluation exclusion, provide information relating to the fleet or plant-specific experience that supports the basis for this change.

RAI B.2.1.13-1

Background:

LRA Section B.2.1.13, "Closed Treated Water System," states that the "Parameters Monitored or Inspected" and "Detection of Aging Effects" program elements will be enhanced by performing condition monitoring inspections on a representative sample of piping and components. While periodic inspections of a representative sample is consistent with the recommendations in GALL Report AMP XI.M21A, Standard Review Plan for License Renewal (SRP-LR) Section A.1.2.3.4 states that the basis for the sample size should be provided whenever sampling is used to represent a larger population of components.

Issue:

Documentation in the LRA and the onsite program basis documents did not include any details about the sample size. The staff could not verify that the size of the representative sample will be sufficient to ensure that the effects of aging would be adequately managed.

Request:

Provide details related to the size of the representative sample associated with the enhancement to the Closed Treated Water System program. As appropriate, include a discussion of the bases for the frequency of inspections to address cracking based on the operating experience discussed in RAI B.2.1.13-3.

RAI B.2.1.13-2

Background:

LRA Section B.2.1.13 states that the Closed Treated Water System manages aging effects including the reduction of heat transfer. During its review of the LRA, the staff noted that the only components where this AMP manages reduction of heat transfer are the heat exchanger tubes in LRA Table 3.3.1-8, "Diesel Generator and Auxiliaries System." The staff also noted that the heat exchanger tubes for the drywell penetration cooling coils in LRA Table 3.3.2-1, "Closed Cycle Cooling Water System," are not being managed for reduction of heat transfer because the cooling provided to the drywell penetrations does not need to be credited for license renewal. In that regard, the staff noted that AMR item 3.5.1-3, associated with aging management of concrete exposed to elevated temperatures, is designated as "not applicable" because localized concrete temperatures greater than 200 °F have not been reported. The staff noted that, while cooling of the drywell penetrations may not be required to be credited, cooling of the drywell penetrations is the reason why localized concrete temperatures greater than 200 °F were not reported.

Issue:

SRP-LR Section A.1.2.1, “Applicable Aging Effects,” states that an aging effect should be identified as applicable for license renewal even if there is a prevention program associated with that aging effect. It is unclear to the staff whether concrete temperatures adjacent to the drywell penetrations would be maintained less than 200 °F without cooling flow to the drywell penetration coils. Unless cooling flow to the drywell penetration coils is being periodically confirmed, it is unclear to the staff how the aging effects related to elevated temperatures in the concrete adjacent to the drywell penetrations can be considered as not applicable.

Request:

For the concrete adjacent to the drywell penetration cooling coils in LRA Table 3.3.2-1, “Closed Cycle Cooling Water System,” either identify the activities that will be credited for ensuring that local temperatures will be maintained less than 200 °F, or provide the plant-specific AMP described in AMR item 3.5.1-3 for managing the reduction of strength and modulus due to elevated temperatures locally greater than 200 °F.

RAI B.2.1.13-3

Background:

LRA Section B.2.1.13 states that the aging effects being managed by the Closed Treated Water System program include cracking. During its review of the LRA, the staff noted that the only components for which this AMP manages cracking are the heat exchanger tubes and tube sheets in LRA Table 3.3.1-8, “Diesel Generator and Auxiliaries System.” Plant-specific operating experience reports AR00299270, AR00200440, and AR00200182, identified cracking in the heat exchanger tubes associated with the reactor recirculation pump motor coolers; however, the staff noted that the heat exchanger tubes and tube side components for the reactor recirculation pump motor coolers in LRA Table 3.1.2-1, “Reactor Coolant Pressure Boundary System,” are not being managed for cracking.

SRP-LR, Section A.1.2.1, “Applicable Aging Effects,” states that the determination of applicable aging effects is based on degradation mechanisms that have occurred and those that potentially could cause structure or component degradation. Section A.1.2.1 also states that relevant aging information may be contained in plant-specific site deviation or issue reports.

Issue:

The applicable aging effects do not appear to be appropriately determined for the aging management of certain components being managed by this AMP, based on plant-specific operating experience reports.

Request:

Either provide the technical bases to show that cracking does not need to be managed in heat exchanger tubes and tube side components for the reactor recirculation pump motor coolers, or provide an additional AMR item that addresses this aging effect. Include a discussion to justify

why this aging effect would not be applicable to other heat exchangers managed by this program for which cracking is not addressed.

RAI B.2.1.13-4

Background:

Monticello's Licensee Event Report 263/2014-001, "Primary System Leakage Found in Recirculation Pump Upper Seal Heat Exchanger," documents intergranular stress corrosion cracking in a stainless steel heat exchanger tube caused by unrecognized localized boiling that led to an unexpected high concentration of chlorides from the chemistry constituents in the reactor building closed cooling water system. Exelon's evaluation of this operating experience report (Issue Report (IR) 1614784-02) identified differences between the heat exchanger configurations at Monticello (described as being internal to the pump and being a "tube within box") and LSCS (described as being external to the pump and being a "tube-within-tube"). The evaluation states that the coil configuration does not allow similar chlorides to concentrate on tubes and that because the heat exchanger is external to the pump, it is visually inspected every outage. The evaluation concludes that the heat exchanger design supports a much less challenging environment for the tubes.

Issue:

In its review of this evaluation, the staff could not conclude that the coil configuration at LSCS would prevent similar chloride concentrations because localized boiling could still occur in the tube-within-tube coil configuration. In addition, although the heat exchanger is external to the pump, visual inspections of the heat exchanger during outages cannot detect cracking of the interior tube, which is where the cracking would occur. Also, although the LSCS heat exchanger design may present a much less challenging environment for the tubes, without specific temperature information it cannot be determined whether localized boiling would occur, leading to a comparable, unexpected high concentration of chlorides. Based on temperature data provided to the staff during the audit, localized boiling within the heat exchanger did not appear to apply to LSCS. However, the evaluation of the industry operating experience documented in IR 1614784-02 did not provide sufficient bases to show that the coil configuration would prevent similar chloride concentration and that localized boiling would not occur.

Request:

For Licensee Event Report 263/2014-001, provide an assessment of the adequacy of the operating experience evaluation documented in IR 1614784-02 and any implications this has on the aging effects being managed by the Closed Treated Water System program.

RAI B.2.1.18-1

Background:

GALL Report AMP XI.M29, "Aboveground Metallic Tanks," as revised by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," states that thickness measurements of tank bottoms are performed

in accordance with Table 4a, “Tank Inspection Recommendations.” Table 4a provides guidance on the frequency of volumetric inspections performed on tank bottoms.

The Aboveground Metallic Tanks AMP has an enhancement (Enhancement No. 3) to perform volumetric inspections in accordance with LR-ISG-2012-02, Table 4a. During the onsite audit of the applicant’s Aboveground Metallic Tanks Program, the staff reviewed operating experience associated with the aging of tank bottoms. The bottoms of both cycled condensate storage tanks have experienced loss of material. The Unit 1 tank, 1CY01T, experienced leakage resulting from pitting in the tank bottom. Patches have been installed on the bottoms of both tanks to repair areas that were found to be below nominal thickness.

Issue:

The sufficiency of Enhancement No. 3 to effectively manage the tank bottoms for loss of material could not be determined during the AMP audit. It is unclear to the staff if the extent and locations of the volumetric inspections being performed are sufficient to manage loss of material during the period of extended operation.

Request:

Provide the extent of the volumetric inspections being performed and the methodology used to select the inspection location. The response should include details such as: (a) considerations being given to previous inspection results and patched locations, (b) percent of tank bottoms being inspected, and (c) grid spacing if discrete Ultrasonic Testing (UT) points are used for inspection. Justify the adequacy of the inspections being performed to manage the loss of material on the tank bottoms given the plant-specific operating experience.

RAI B.2.1.18-2

Background:

GALL Report AMP XI.M29, “Aboveground Metallic Tanks,” as revised by LR-ISG-2012-02, states that caulk is applied to the interface of the tank bottom and foundation of outdoor tanks to mitigate the corrosion of tank bottoms. Table 3.0-1, “FSAR Supplement for Aging Management of Applicable Systems,” of the SRP-LR, as revised by LR-ISG-2012-02, states that visual examinations are sufficient to monitor the degradation of caulking when supplemented with physical manipulation.

The Aboveground Metallic Tanks AMP has an enhancement (Enhancement No. 4) to perform visual inspections of the caulking at the interface of the tank bottom and foundation of the outdoor tanks for signs of degradation during each refueling interval.

Issue:

The sufficiency of Enhancement No. 4 to mitigate the corrosion of tank bottoms could not be determined during the AMP audit. The loss of material experienced by the tank bottoms has been partially attributed to chloride and moisture intrusion resulting from the failure of the flexible caulk seal at the interface of the tank bottom and foundation. It is unclear to the staff if

visual inspections of the caulk, without being augmented with physical manipulation, are sufficient to manage the degradation of the caulk during the period of extended operation.

Request:

Provide and justify the technical basis used to determine that the visual inspection of the caulking at the interface of the tank bottom and foundation, without supplemental physical manipulation, is adequate to assess the degradation of the caulking.

RAI B.2.1.23-1

Background:

GALL Report AMP XI.M35 states under the Detection of Aging Effects program element that "[t]his inspection should be performed at a sufficient number of locations to ensure an adequate sample. This number, or 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."

LRA Sections B.2.1.23 and A.2.1.23 do not provide the total number of in-scope small-bore piping welds.

Issue:

The LRA does not provide the weld populations. It is not clear to the staff how the inspection sample will be selected and thus whether a sufficient number of locations will be inspected to ensure that cracking will be adequately managed.

Request:

Provide the population of in-scope small-bore piping welds for each weld type (i.e., butt welds and socket welds) at each unit. Based on the population, justify the adequacy of the selected sample size for each type of weld.

RAI B.2.1.23-2

Background:

GALL Report AMP XI.M35 states under the Detection of Aging Effects program element that the one-time inspection program does not apply to plants that have experienced cracking in ASME Code Class 1 small-bore piping due to stress corrosion, cyclical (including thermal, mechanical, and vibration fatigue) loading, or thermal stratification and thermal turbulence. LRA Section B.2.1.23 states that LSCS has not experienced this type of cracking. However, the LRA also states that the applicant's review identified two issues with ASME Code Class 1 small-bore piping welds during startup of LaSalle County Station, Unit 1, in 1983. The LRA further states that a pinhole leak was identified on a LaSalle County Station, Unit 2, ASME Code Class 1 small-bore socket weld in 2005. The LRA states that the pinhole leak was caused by an inclusion or defect in a repair weld performed in 1995.

Issue:

The staff reviewed the two issues identified for Unit 1 and noted that for both events, cracking was noted at a socket weld connection. Analyses of these events in 1983 revealed that the most likely cause of the event was an improper weld application or installation. However, the analyses did not yield a specific procedural non-compliance, but noted that the selected post weld heat treatment and filler metal selection was less than optimal. The analyses also noted that vibration may have contributed to crack propagation.

The staff also reviewed the leakage event identified for Unit 2, in 2005. The staff noted that the leakage occurred at the same location as the two cracking events identified for Unit 1 in 1983. The staff also noted that the 2005 event was attributed to a possible weld defect from a prior repair performed in 1995. It was assumed that a subsurface inclusion or porosity existed from the 1995 repair, which resulted in leakage in 2005.

Based on its review of the available information, the staff determined that the documented failures were very likely age-related, caused by vibration and/or thermal fatigue.

Request:

Provide information in terms of metallurgical analysis to support the determination that the multiple socket weld failures described above do not constitute failures of ASME Code Class 1 small-bore piping due to cyclical mechanical or thermal fatigue.

If the above failures of ASME Code Class 1 small-bore socket welds could be attributed to vibration or thermal fatigue, provide a plant-specific program that includes periodic inspections; otherwise, justify how the One-time Inspection of ASME Code Class 1 Small-Bore Piping program will adequately manage cracking consistent with the guidance provided in the GALL Report AMP.

RAI 4.1-1

Background:

In LRA Table 4.1-1, the applicant identifies that the current licensing basis (CLB) does not include any Time Limited Aging Analyses (TLAAs) associated with a flow-induced vibration limit for reactor vessel internal (RVI) components at LSCS.

Issue:

Updated Final Safety Analysis Report (UFSAR) Section 3.9.2.4 indicates that flow-induced vibrations of the RVI components were assessed as part of a pre-operational testing program and that the results of the program were summarized in General Electric (GE) Report No. NEDO-24057-P, “Assessment of Reactor Internals Vibration in BWR/4 and BWR/5 Plants,” dated November, 1977. However, the staff noted that the UFSAR does not indicate whether the methodology in GE Report No. NEDO-24057-P included a time-dependent analysis for qualifying the structural integrity of the RVI components against the consequences of age-related effects caused by flow-induced vibrations.

Request:

Clarify whether the methodology in GE Report No. NEDO-24057-P included a time-dependent analysis, and if so, whether the analysis is relied upon to qualify the structural integrity of the RVI components against the consequences of aging effects caused by flow-induced vibrations. If the analysis is time-dependent, identify the aging effects and justify why the analysis would not need to be identified as a TLAA, when compared to the six criteria for qualifying analyses as TLAAs in 10 CFR 54.3(a).

RAI 4.1-2

Background:

In the staff's safety evaluation (SE) on EPRI BWRVIP Technical Report (TR) No. BWRVIP-26-A dated December 7, 2000 (ADAMS Accession No. ML003776110), the staff issued Applicant Action Item (AAI) No. 4, requesting the BWR applicant's identification of any plant-specific TLAAs that may be applicable to the evaluation of BWR top guide components. In its response to this AAI, as provided in Appendix C of the LRA, the applicant states that the RAMA code fluence evaluation for the RVI components determined that the neutron fluence threshold for irradiation-assisted stress corrosion cracking (IASCC) susceptibility of the top guides has been exceeded. The applicant states that the fluence for RVI components is evaluated as a TLAA in LRA Section 4.2.1. The applicant states that no other TLAA has been identified to manage the effects of aging for the top guides and their components and that, during the period of extended operation, the aging of the top guide will be managed by inspections that are conducted as part of the BWR Vessel Internals program (LRA Section B.2.1.9).

Issue:

The applicant's response to AAI No. 4 on the BWRVIP-26-A report does not specifically state or address whether the CLB included any analysis of irradiation-induced or irradiation-assisted stress corrosion cracking in the top guide assemblies (or the subcomponents in the top guide assemblies) that would need to be identified as a TLAA for the LRA. The staff seeks additional clarification.

Request:

Clarify whether the current licensing or design basis includes an analysis or evaluation of irradiation-induced or irradiation-assisted SCC in LaSalle's top guide assemblies or components. If so, justify why the analysis would need to be identified as a TLAA when compared to the six criteria for qualifying analyses as TLAAs in Title 10 of the *Code of Federal Regulations* (10 CFR), Section 54.3(a).

RAI 4.1-3

Background:

In LRA Section 4.1.2, the applicant states that it reviewed those exemptions previously granted in accordance with the requirements in 10 CFR 50.12 that apply to LSCS. The applicant states that none of the exemptions were associated with or supported by TLAAs. Therefore, the

applicant stated that no further evaluation of these exemptions is required by the regulation in 10 CFR 54.21(c)(2).

<u>Issue</u>:

3. The operating licenses for LSCS identify that the applicant was granted specific exemptions from the requirements in 10 CFR Part 50, Appendix G, which is the rule that applies to the performance of mandated time-dependent pressure-temperature limit (P-T limit) and upper shelf energy (USE) analyses. The applicant was granted specific exemptions from meeting the requirements for certain types of containment leak rate testing activities under 10 CFR Part 50, Appendix J. However, neither the LRA nor the operating licenses specify what these exemptions involved. Therefore, the staff does not currently have sufficient information to make a determination as to whether these exemptions (as granted under 10 CFR 50.12) were based on a TLAA.

4. By letter dated November 8, 2000 (ADAMS Accession No. ML003771016), the staff granted specific exemptions in accordance with 10 CFR 50.12 to use analytical methods in ASME Code Cases N-640 and N-588 for P-T limit calculations of LSCS. In previous submittals, Exelon identified that these types of exemptions met the requirements in 10 CFR 54.21(c)(2). However, Exelon has not identified that the identical exemptions for LSCS meet the criteria in 10 CFR 54.21(c)(2).

<u>Request</u>:

1. Provide your basis why the exemptions listed in the operating licenses from 10 CFR Part 50, Appendix G, or 10 CFR Part 50, Appendix J, requirements are not considered as exemptions remaining in effect that were granted in accordance with 10 CFR 50.12 based on a TLAA. If it is determined that these exemptions were previously granted in accordance with 10 CFR 50.12, the exemptions remain in effect for the CLB, and they are based on a TLAA, provide your basis for not amending your LRA and submit an evaluation of the exemptions in accordance with the requirements in 10 CFR 54.21(c)(2).

2. Justify why exemptions to use ASME Codes N-640 and N-588 at LSCS have not been identified as exemptions granted in accordance with 10 CFR 50.12 and are based on a TLAA.