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

April 3, 2014

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

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE BYRON STATION, UNITS 1 AND 2, AND BRAIDWOOD STATION, UNITS 1 AND 2, LICENSE RENEWAL APPLICATION, SET 16 (TAC NOS. MF1879, MF1880, MF1881, AND MF1882)

Dear Mr. Gallagher:

By letter dated May 29, 2013, Exelon Generation Company, LLC, submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part 54, to renew the operating licenses NPF-37, NPF-66, NPF-72, and NPF-77 for Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, respectively, for review by the U.S. Nuclear Regulatory Commission (NRC or the staff). 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 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 301-415-4115 or e-mail by Lindsay.Robinson@nrc.gov.

Sincerely,

Lindsay R. Robinson, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-454, 50-455, 50-456, and 50-457

Enclosure:
Request for Additional Information

cc w/encl: Listserv

April 3, 2014

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Vice President, License Renewal Projects
Exelon Generation Company, LLC
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Kennett Square, PA 19348

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Letter to M.P. Gallagher from Lindsay R. Robinson dated April 3, 2014

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BYRON STATION, UNITS 1 AND 2,
AND BRAIDWOOD STATION, UNITS 1 AND 2,
LICENSE RENEWAL APPLICATION
REQUEST FOR ADDITIONAL INFORMATION, SET 16
(TAC NOS. MF1879, MF1880, MF1881, MF1882)

RAI 3.0.3-2a

Applicability:

Byron Station (Byron) and Braidwood Station (Braidwood), Units 1 and 2

Background:

As amended by letter dated January 13, 2014, Exelon Generation Company, LLC provided the following information:

1. License renewal application (LRA) Table 3.2.2-4 states that loss of coating integrity for the safety injection pump oil reservoirs will be managed by the Lubricating Oil Analysis program. The request for additional information (RAI) response states that oil sampling and oil change activities are capable of detecting coating degradation by detecting particulate in the oil which would indicate degradation of the internal lining of the reservoir or of the base metal.
2. The response to RAI 3.0.3-2 states that components associated with the caustic and acid supply to the radwaste system demineralizers, hypochlorite injection to the discharge of the essential service water pumps, and 0C auxiliary building chiller condenser at Byron Station (Byron), all not in service, have internal coatings. The response also states that these coatings are not exposed to the aggressive internal environment for which the coating was required and visual inspections of these components is performed in accordance with the requirements of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program.

   LRA Tables 3.3.2-20 and 3.3.2-22 state that loss of coating integrity will be managed for carbon steel (with internal coating or lining) piping, piping components, tanks, heat exchangers, and valve bodies exposed to waste water by the Internal Surfaces in Miscellaneous Piping and Ducting Components program. LRA Table 3.0-1 states that, "waste water may contain contaminants, including oil and boric acid, depending on location, as well as originally treated water that is no longer monitored by a chemistry program." The Generic Aging Lessons Learned (GALL) Report item AP-281 states that steel components exposed to waste water are susceptible to loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion.

   As amended, LRA Sections A.2.1.25 and B.2.1.25 state that (a) internal coatings of components are visually inspected; (b) a representative sample of components will be inspected each 10-year period during the period of extended operation; and (c) a sample population is defined as components having the same combination of material, environment, and aging effect.
3. The response to RAI 3.0.3-2 states that inspections of coated heat exchangers cooled by the service water system are performed every 2 to 6 years. It also states that inspection frequencies are based on criticality of the heat exchanger, prior inspection results, and service conditions.
4. The response to RAI 3.0.3-2 states that diesel oil storage tank internal inspections, including its coatings, will be conducted once in the 10-year period prior to the period of

extended operation and at least once every 10 years during the period of extended operation. LRA Sections A.2.1.18 and B.2.1.18 were revised to state that the Fuel Oil Chemistry program manages loss of coating integrity.

5. The response to the RAI states that 100 percent of the coated surfaces that are accessible upon component disassembly are visually inspected each inspection interval. LRA Tables 3.3.2-20 and 3.3.2-22 state that loss of coating integrity is being managed for piping and piping components.

6. The response to the RAI states that Service Level III coating inspections are performed by individuals certified to the American National Standards Institute (ANSI) N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants." The response also states that Service Level II coatings are inspected by system managers or maintenance personnel using procedural guidance and that they qualified in accordance with the Institute of Nuclear Power Operations (INPO) National Academy for Nuclear Training accredited training program that meets industry standards described in ACAD 92-008, "Guidelines for Training and Qualification of Maintenance Personnel."

7. The response to the RAI states that the as-found condition of coatings is documented in inspection reports and that previous inspections are used to determine changes in the condition of coatings. The response also states that inspection reports are provided to the site coatings coordinator.

8. The RAI response states, "[a]ny loss of coating integrity such that loss of material of the base metal occurs is considered a coating failure. Localized areas of loss of coating integrity without subsequent loss of material of the base metal are considered acceptable. Plant-specific operating experience has shown that this acceptance criteria is adequate to ensure the intended function(s) of the coated components, and, if applicable, downstream components are maintained."

Issue:

1. The staff recognizes that oil samples taken from the safety injection pump oil reservoir are capable of detecting particulate from degraded coatings or corrosion products where bare metal had been exposed. However, debris from coating degradation generated between samples could reduce the flow to the pump bearings and result in the loss of the pump's current licensing basis intended function(s). An internal visual inspection could identify precursor degradation. Additionally, oil changes could result in removing evidence of gradual coating degradation.

   It is not clear to the staff that the internal coated surfaces of the safety injection pump oil reservoir will be in the sample population of the One-Time Inspection program for components exposed to lubricating oil. In addition, it is not clear to the staff whether a one-time inspection is appropriate for this coating as it continues to age.

2. Although the RAI response states that the coatings for components associated with the caustic and acid supply to the radwaste system demineralizers, hypochlorite injection to the discharge of the essential service water pumps, and 0C auxiliary building chiller condenser at Byron are not exposed to the aggressive internal environment for which the coating was required, the LRA states that these components are exposed to waste water; the GALL Report states that loss of material is an applicable aging effect for these components. The staff concludes that, should the coatings degrade such that base metal is exposed, through-wall corrosion could occur. The staff has the following concerns in relation to use of the Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage loss of coating integrity for these components:

a. The program is based on a 10-year inspection frequency; whereas, the staff has concluded that the maximum inspection interval should be 6 years, 4 years, or 2 years depending on the conditions detected during inspections and whether the coatings have been recently repaired or replaced.

b. It is not clear to the staff that coated steel components would be considered as a unique sample population.

c. The staff has concluded that the updated final safety analysis report (UFSAR) supplement for programs that will manage loss of coating integrity should include key aspects of the program associated with coating degradation such as followup testing that will be conducted when degradation is determined not to meet acceptance criteria and the basis for the training and qualification of individuals involved in coating inspections. These aspects are not in LRA Section A.2.1.25.

d. The staff has concluded that the programs credited for detecting loss of coating integrity should include a summary description in the LRA of: (a) when baseline inspections will be conducted, (b) the extent of inspections, (c) qualifications for individuals performing activities associated with coating inspections, (d) how monitoring and trending of the coatings will be conducted, (e) acceptance criteria, and (f) corrective actions when coating degradation is detected. These details are not in LRA Section B.2.1.25.

In addition, similar to the issues listed in 2.c. and 2.d. above, LRA Sections A.2.1.11 and B.2.1.11 for the Open-Cycle Cooling Water System program and A.2.1.18 and B.2.1.18 for the Fuel Oil Chemistry program lack sufficient specificity.

3. The staff has concluded that, when peeling, delamination, blisters, rusting, cracking, or flaking has been detected during coating inspections, subsequent inspection intervals are established by a qualified coating specialist. The staff also concluded that intervals should not exceed every other refueling outage interval.

4. The staff has concluded that coating inspections for diesel oil storage tanks may be conducted at the frequency stated in the Fuel Oil Chemistry program as long as: (a) no peeling, delamination, blisters, or rusting are observed during inspections and (b) any cracking and flaking has been found acceptable by a coating specialist. If this is not the case, inspections should be conducted more frequently.

5. While the statement that 100 percent of the coated surfaces that are accessible upon component disassembly are visually inspected each inspection interval is clear in relation to tanks and heat exchangers, it does not provide sufficient clarity for inspections of piping and piping components. The staff has concluded that for piping and piping components, either representative 73 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating material and environment combination should be inspected in each interval.

6. ANSI N45.2.6 certification is an acceptable basis for qualifying coatings inspectors based on Regulatory Guide (RG) 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants," June 1973, Section C.1., which mandates conformance to the ANSI N45.2 quality assurance standards. Subsequent revisions of RG 1.54 endorsed the American Society for Testing and Materials (ASTM) standards which specifically address inspector qualifications as they were released to industry.

It appears to the staff that the reference to Service Level II coatings (nonsafety-related coatings) would encompass coatings applied to the internal surfaces of components described in the RAI response (e.g., associated with the caustic and acid supply to the radwaste system demineralizers, hypochlorite injection to the discharge of the essential service water pumps, and 0C auxiliary building chiller condenser at Byron). The staff has concluded that any coatings applied to the internal surfaces of an in-scope component where degradation of the coating could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(1), (a)(2), or (a)(3) should be inspected by personnel qualified in accordance with a standard endorsed in RG 1.54. While the staff has reviewed and endorsed the use of ANSI N45.2.6 as well as ASTM standards referenced in RG 1.54 for inspection personnel, it has not reviewed and endorsed ACAD 92-008. In addition, it is not clear to the staff that system managers would be qualified in accordance with an ACAD standard for training maintenance personnel.

7. The staff has concluded that the coatings specialist should prepare a post-inspection report to include: a list and location of all areas evidencing deterioration, a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage, and where possible, photographic documentation indexed to inspection locations. The RAI response did not provide this specificity. The post-inspection report should be compiled or approved by a coatings specialist, include sufficient information to ensure that degraded areas are appropriately dispositioned through the corrective action program, and select future inspection locations based on known areas where degradation has occurred.

8. The staff has concluded that:

    a. Indications of peeling and delamination are not acceptable, and the coatings should be repaired or replaced. For coated surfaces that show evidence of delamination or peeling, physical testing should be performed where physically possible (i.e., sufficient room to conduct testing). The test should consist of destructive or nondestructive adhesion testing using ASTM International standards endorsed in RG 1.54. A minimum of three sample points adjacent to the defective area should be tested.

    b. Blisters should be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54, including staff guidance associated with use of a particular standard. The cause of blisters should be determined if the blister is not repaired. Physical testing should be conducted to ensure that the blister is completely surrounded by sound coating bonded to the surface. If coatings are credited for corrosion prevention, the component's base material in the vicinity of the blister should be inspected to determine if unanticipated corrosion has occurred.

    c. Indications such as cracking, flaking, and rusting should be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff guidance associated with use of a particular standard.

    The response to the RAI is not consistent with the staff's position. For example, the revised program: (a) would allow peeling or delamination as long as it did not expose the base metal and was accompanied with loss of base material; (b) does not state that a coatings specialist would evaluate blisters, cracking, flaking, or rusting; and (c) does

not state that followup physical testing would be conducted when delamination, peeling, or blistering is detected. While the response stated that plant-specific operating experience has shown that the acceptance criteria are adequate, no specific information was provided to justify the statement.

Request:

1. State the basis for why debris from coating degradation generated between samples will not result in flow blockage of the oil supply to the safety injection pump bearings. State the basis for why oil changes will not result in reduced sensitivity to gradual coating degradation.

   State whether the internal coated surfaces of the safety injection pump oil reservoir will be in the sample population of the One-Time Inspection program for components exposed to lubricating oil. State the basis for why a one-time inspection is appropriate for this coating.

2. Respond to the following in relation to components for which loss of coating integrity is being managed by the Internal Surfaces in Miscellaneous Piping and Ducting Components program:

   a. State the basis for why a 10-year inspection frequency is adequate.

   b. State whether coated steel components will be considered as a unique sample population. If not, state the basis for sample selection of these components.

   c. Revise LRA Section A.2.1.25 to include a summary description of followup testing that will be conducted when degradation is determined not to meet acceptance criteria and the basis for the training and qualification of individuals involved in coating inspections.

   d. Revise LRA Section B.2.1.25 to include a summary description of: (a) when baseline inspections will be conducted, (b) the extent of inspections, (c) qualifications for individuals performing activities associated with coating inspections, (d) a summary description of how monitoring and trending of the coatings will be conducted, (e) acceptance criteria, and (f) a summary description of corrective actions when coating degradation is detected.

   Additionally, revise LRA Sections A.2.1.11, B.2.1.11, A.2.1.18, and B.2.1.18 as described in request 2.c. and 2.d. above.

3. For heat exchangers cooled by the service water system, state the basis for why it can be concluded that that there is reasonable assurance that loss of coating integrity will not result in accelerated degradation caused by localized coating failures or degraded downstream component performance due to flow blockage if: (a) prior component inspections detected peeling, delamination, blisters, rusting, cracking, or flaking and (b) subsequent inspections will exceed 2 refueling outage intervals.

   Alternatively, revise the Open-Cycle Cooling Water System program to require inspections at least every other refueling outage interval when peeling, delamination, blisters, rusting, cracking, or flaking has been detected during coating inspections.

4. State the periodicity of inspections for the diesel oil storage tank internal coatings and the basis for the periodicity of inspections, if the prior inspection detected peeling, delamination, blisters, rusting, or unacceptable cracking and flaking.

5. State the minimum inspection size and its basis for internally coated piping and piping components.

6. State the qualification requirements included in the system manager and maintenance personnel INPO accredited training programs that establish proficiency in coating inspections, or revise the applicable aging management programs such that coating inspectors are certified to ANSI N45.2.6 or ASTM Standards endorsed in RG1.54.
7. State the qualifications of the individual who will approve post-inspection reports and the key information that will be included in the report.
8. State the following in relation to the acceptance criteria for coatings:
    a. The specific basis for why peeling, delamination, blisters, cracking, flaking, or rusting, which does not result in loss of material of the base metal, will not result in loss of function of a component due to corrosion or degradation of downstream component performance prior to the next inspection interval.
    b. The qualifications of the individual who will evaluate indications of blisters, cracking, flaking, or rusting.
    c. Whether followup physical testing will be conducted when delamination, peeling, or blistering is detected, and if not, the basis for not performing physical testing.