Exelon Generation

Michael P. Gallagher
Vice President, License Renewal
Exelon Nuclear

200 Exelon Way
Kennett Square, PA 19348

610 765 5958 Office
610 765 5956 Fax
www.exeloncorp.com

michaelp.gallagher@exeloncorp.com

**Withhold from Public Disclosure in accordance with 10 CFR 2.390. Upon removal of Enclosure B, this letter is uncontrolled.**

10 CFR 50
10 CFR 51
10 CFR 54

RS-14-084

March 28, 2014

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001
March 28, 2014
U.S. Nuclear Regulatory Commission

Braidwood Station, Units 1 and 2
Facility Operating License Nos. NPF-72 and NPF-77
NRC Docket Nos. STN 50-456 and STN 50-457

Byron Station, Units 1 and 2
Facility Operating License Nos. NPF-37 and NPF-66
NRC Docket Nos. STN 50-454 and STN 50-455

Subject: Responses to NRC Requests for Additional Information, Set 10, dated February 26, 2014 related to the Braidwood Station, Units 1 and 2 and Byron Station, Units 1 and 2 License Renewal Application

References: 1. Letter from Michael P. Gallagher, Exelon Generation Company LLC (Exelon) to NRC Document Control Desk, dated May 29, 2013, "Application for Renewed Operating Licenses."

2. Letter from John W. Daily, US NRC to Michael P. Gallagher, Exelon, dated February 26, 2014, "Requests for Additional Information for the Review of the Byron Nuclear Station, Units 1 and 2, and Braidwood Nuclear Station, Units 1 and 2, License Renewal Application – Aging Management, Set 10 (TAC NOS. MF1879, MF1880, MF1881, and MF1882)"

In the Reference 1 letter, Exelon Generation Company, LLC (Exelon) submitted the License Renewal Application (LRA) for the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2 (BBS). In the Reference 2 letter, the NRC requested additional information to support the staffs' review of the LRA.

Enclosures A and B contain the responses to these requests for additional information.

Enclosure A contains non-proprietary responses.

Enclosure B contains the responses that Westinghouse considers to be proprietary in nature. Enclosure B was prepared and classified as Westinghouse Proprietary Class 2. Westinghouse requests that the RAI responses contained within Enclosure B be considered proprietary in its entirety. As such, a non-proprietary version will not be issued. As Enclosure B contains information proprietary to Westinghouse Electric Company LLC, it is supported by an Affidavit signed by Westinghouse, the owner of the information. The Affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)( 4) of Section 2.390 of the Commission's regulations. Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR Section 2.390 of the Commission's regulations. Correspondence with respect to the copyright or proprietary aspects of the item listed above or the supporting Westinghouse Affidavit should reference CAW-14-3934 and should be addressed to James A. Gresham, Manager, Regulatory Compliance, Westinghouse Electric Company, Suite 310, 1000 Westinghouse Drive, Cranberry Township, Pennsylvania 16066.

Enclosure C provides the Westinghouse Application for Withholding Proprietary Information from Public Disclosure CAW-14-3934, accompanying Affidavit, Proprietary Information Notice, and Copyright Notice.

Enclosure D contains updates to sections of the LRA affected by the responses.

There are no new or revised regulatory commitments contained in this letter.

If you have any questions, please contact Mr. Al Fulvio, Manager, Exelon License Renewal, at 610-765-5936.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 03-28-2014

Respectfully,

Michael P. Gallagher

Michael P. Gallagher
Vice President - License Renewal Projects
Exelon Generation Company, LLC

Enclosures: A: Responses to Requests for Additional Information (non-proprietary)
B: Responses to Requests for Additional Information (proprietary)
C: Westinghouse affidavit supporting proprietary responses
D: Updates to affected LRA sections

cc: Regional Administrator – NRC Region III (w/o Enclosure B)
NRC Project Manager (Safety Review), NRR-DLR (w/o Enclosure B)
NRC Project Manager (Environmental Review), NRR-DLR (w/o Enclosure B)
NRC Senior Resident Inspector, Braidwood Station (w/o Enclosure B)
NRC Senior Resident Inspector, Byron Station (w/o Enclosure B)
NRC Project Manager, NRR-DORL-Braidwood and Byron Stations (w/o Enclosure B)
Illinois Emergency Management Agency - Division of Nuclear Safety (w/o Enclosure B)

# Enclosure A

## Byron and Braidwood Stations (BBS), Units 1 and 2
## License Renewal Application
## Responses to Requests for Additional Information

## Non-Proprietary Information

RAI 4.3.1-4
RAI 4.3.3-1
RAI 4.7.5-1
RAI 4.7.5-2
RAI 3.2.1.20-1
RAI 3.1.1.80-1
RAI 3.1.1.81-1
RAI 4.7.4-1
RAI 4.1-1
RAI 4.1-2

**RAI 4.3.1-4, Frequency of samples for Sampling Line and Nozzle Transients (060)**

**Applicability:** Byron and Braidwood

**Background:**

LRA Table 4.3.1-2 and 4.3.1-4 state that Transient 14, “Sampling Line and Nozzles Transients,” will not be monitored. The LRA states that chemistry samples are taken at a much lower frequency than that which was assumed in the design, resulting in fewer cycles. The LRA further states that samples are no longer taken from the RCS as specified in the design, and are taken instead from the letdown system. The LRA states that samples from the letdown system result in lower temperature differences and lower transient severity.

**Issue:**

The applicant did not provide enough information regarding the lower frequency and temperature differences when taking chemistry samples from the letdown system instead of the RCS system. The staff is unclear how the lower frequency and temperature differences support the basis for not monitoring Transient 14.

**Request:**

1. Provide the comparison of frequencies at which chemistry samples are taken from the letdown system instead of the RCS system. Explain and justify why this less frequent sampling supports the basis for not monitoring Transient 14.

2. Provide the comparison of temperature differences from taking the chemistry samples from the letdown system instead of the RCS system. Explain and justify why the lower temperature differences support the basis for not monitoring Transient 14.

**Exelon Response:**

1. The original sample location and design assumption for frequency of chemistry samples were compared with the actual sample location and plant procedures for chemistry sampling frequency. The original design transient cycle basis assumed that samples were taken, through sample line piping connected directly to the Reactor Coolant System (RCS), three (3) times per day, over a 40-year plant life for a total of 45,000 cycles. However, chemistry procedures, as confirmed by operator interviews, show that RCS samples are actually taken only once per day during power operations and up to a maximum of once per hour, for a maximum of three days, during each heatup and cooldown.

   Starting in approximately 2002, the reactor coolant sampling location was changed such that all four BBS units began drawing chemistry samples downstream of the Chemical Volume and Control System letdown heat exchangers. The maximum number of thermal cycles experienced by the original sample line piping from the RCS, based on the unit that has been in service the longest (Byron Unit 1) through 2002, is estimated to be approximately 11,000. Therefore, the cycles experienced to date is considerably less than that assumed for the 40-year design basis (45,000), and justifies not monitoring transient 14, “Sampling Line and Nozzles Transients.”

As explained in the response to Request 2 below, since the transient temperature differences experienced by the letdown sample line piping is 80°F or less, fatigue is not a concern and cycle counting is not necessary.

2. A sample line remains at ambient temperature (approximately 70°F) during times when sampling is not occurring. A transient occurs when a sample is drawn and sample line heats up from ambient temperature to the temperature of the fluid being sampled. When samples were originally taken from the RCS (with typical operating temperatures of approximately 550°F to 650°F) through the RCS sample line piping, the transient in the RCS sample line piping were more severe in terms of temperature difference (approximately 480°F to 580°F). When samples are taken from the letdown sample line piping downstream of the letdown heat exchangers, which have a bounding operating temperature range of approximately 90°F to 150°F, the corresponding transient in the letdown sample line piping is considerably less severe in terms of temperature difference (approximately 20 to 80°F). Because the transient temperature difference is significantly less in letdown sample line piping than it was when samples were taken from RCS sample line piping, fatigue is not a concern. The combination of less frequent sampling, as discussed in Request 1 above, and less severe temperature transients on the sample line demonstrates that actual operating fatigue impacts are insignificant and provides the basis for not monitoring transient 14, "Sampling Line and Nozzles Transients."

**RAI 4.3.3-1,** Metal fatigue analysis information on auxiliary feedwater, emergency diesel generator and other systems (060)

**Applicability**: Byron and Braidwood

**Background**:

LRA Section 4.3.3 states that implicit fatigue analyses were evaluated for piping and components designed in accordance with ASME Section III, Class 2 and 3, and ANSI B31.1 design rules. LRA Table 4.3.1-3 and Table 4.3.1-6 lists the transients and their 60-year projections for the Class 2 and 3 and ANSI B31.1 piping considered to experience transients associated with the Reactor Coolant System and Auxiliary Systems. The LRA states that these transients were summed to verify that they were less than 7,000 cycles.

LRA Section 4.3.3 further states that an operational review was performed on remaining systems that are affected by different thermal and pressure cycles. The LRA states that the review concluded that the total number of cycles projected for 60 years are significantly less than 7,000 cycles. The LRA states that these remaining systems include the Auxiliary Feedwater, Emergency Diesel Generator, Fire Protection, Heating Water and Heating Steam System, and Service Water Systems. The applicant dispositioned the time-limited aging analysis (TLAA) in accordance with 10 CFR Part 54.21(c)(1)(i) such that the ASME Section III, Class 2 and 3, and ANSI B31.1 allowable stress calculations for the remaining systems remain valid for the period of extended operation.

**Issue**:

The applicant provided the 60-year cycle projections for the transients associated with the Class 2 and 3 and ANSI B31.1 piping in the reactor coolant system and auxiliary systems. However, the applicant did not provide enough information for the auxiliary feedwater, emergency diesel generator, fire protection, heating water and heating steam system, and service water systems. The staff requires additional clarification on the transients and 60-year projections on these remaining systems.

**Request**:

For ***each*** of the following systems: auxiliary feedwater, emergency diesel generator, fire protection, heating water and heating steam system, and service water systems:

a) Provide the transients used in the implicit fatigue analysis
b) For each of these transients, provide the current cycle count, projected 60 year count, and justification for the 60-year projections.
c) Justify that the TLAA remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

**Exelon Response**:

Since the responses for Auxiliary Feedwater System, Emergency Diesel Generator, Fire Protection System, and Service Water System are very similar a common response is provided as follows:

a) Transients used in the implicit fatigue analysis of the:
   - Auxiliary Feedwater System are the number of auxiliary feedwater pump diesel engine starts and stops,
   - Emergency diesel generators are the number of diesel engine starts and stops,
   - Fire Protection System are the number of fire pump diesel engine starts and stops, and
   - The Byron Service Water (SX) System are the number of SX makeup pump diesel engine starts and stops. Braidwood does not have SX make up pumps.

   The piping and piping components associated with these diesel engines were designed, procured, fabricated, and installed consistently with ANSI B31.1. Therefore, these pipe and piping components are associated with an implicit fatigue analysis and were inherently designed for at least 7,000 thermal cycles. These piping and piping components experience one (1) temperature transient each time a diesel engine starts up, runs, and then shuts down.

b) LRA Section 4.3.3 has dispositioned these transients in accordance 10 CFR 54.21(c)(1)(i) and cycle counting is not required. As such, each site does not count the current number of cycles. Each diesel engine is started and shutdown once a month for surveillance to satisfy technical specifications. Over a 60 year period, piping and piping components associated with each diesel engine will experience approximately 720 thermal cycles during surveillance testing. Additional cycles may occur when each diesel engine is called upon to: 1) run and perform its intended function, 2) run for additional surveillance testing requirements, 3) run during spurious starts, or 4) run as a result of maintenance activities. These cycles are conservatively assumed to be no more than 720. Therefore, each diesel engine will experience no more than approximately 1,440 thermal cycles during the during a 60 year operating period which is significantly less than the ANSI B31.1, 7,000 cycle design input.

c) During a 60 year operating period, piping and piping components associated with each diesel engine will experience significantly less thermal cycles than the inherent design input of 7,000 cycles, ensuring substantial margin. Therefore, the maximum allowable stress range reduction factor (i.e., 1.0) for the existing implicit ANSI B31.1 fatigue analysis remains valid because the allowable limit for the number of full range transients would not be exceeded during the period of extended operation.

The following response is provided for the Heating Water and Heating Steam System:

a) Transients used in the implicit fatigue analysis of the Heating Water and Heating Steam System are the number of auxiliary steam system startups and shutdowns. Auxiliary steam system piping and piping components were designed, procured, fabricated, and installed consistently with ANSI B31.1. Therefore, these piping and piping components are

associated with an implicit fatigue analysis and were inherently designed for at least 7,000 thermal cycles. The auxiliary steam system portion of the system supplies steam, in some cases continuously, to various plant equipment. This system has the capability of supplying steam to these loads from the extraction steam system from either unit. The auxiliary steam boilers are used only as back up to the extraction steam supply during dual unit outages or for surveillances. Therefore, the auxiliary steam system piping and piping components experience thermal and pressure transients when extraction steam supply becomes unavailable during a dual unit shutdown or during surveillances when an auxiliary steam boiler is placed in service.

b) LRA Section 4.3.3 has dispositioned these transients in accordance 10 CFR 54.21(c)(1)(i) and cycle counting is not required. As such, each site does not count the current number of cycles. The auxiliary steam system, which is common to both units, is normally supplied by extraction steam from either unit. The auxiliary steam boilers are used only as back up when extraction steam is not available. Therefore, a thermal cycle of the auxiliary steam system would occur only when the extraction steam supply from both units is simultaneously lost (i.e., dual unit outage), which require the start up of the auxiliary steam boilers, or during auxiliary steam boiler surveillances. Therefore, the projected number of thermal cycles over 60 years is conservatively estimated to be no more than the maximum projected occurrences of plant cooldowns and heatups, reactor trips, and surveillances for a single auxiliary steam boiler (Byron Unit 1 is used as it has the greatest number of projected occurrences). Therefore, assuming each auxiliary steam system is cycled each time: 1) a unit cooldown and heatup with a maximum 60 year projection of 117 occurrences (transients 1 and 2 on LRA Tables 4.3.1-3 and 4.3.1-6); 2) a unit experiences a reactor trip with a maximum 60 year projection of 71 occurrences (transients 23, 24, and 25 on LRA Tables 4.3.1-3 and 4.3.1-6); and 3) during the performance of three (3) auxiliary steam boiler surveillances per year over a 60 year period for a total of 180 occurrences. Therefore, auxiliary steam system will experience no more than 368 thermal cycles during the during a 60 year operating period which is significantly less than the ANSI B31.1, 7,000 cycle design input.

c) During a 60 year operating period, piping and piping components associated with each auxiliary steam system will only experience significantly less thermal cycles than the inherent design input of 7,000 cycles, ensuring substantial margin. Therefore, the maximum allowable stress range reduction factor (i.e., 1.0) for the existing implicit ANSI B31.1 fatigue analysis remains valid because the allowable limit for the number of full range transients would not be exceeded during the period of extended operation.

**RAI 4.7.5-1,** Reactor coolant pump flywheel fatigue crack growth analyses (067)

**Applicability**: Byron and Braidwood

**Background**:

LRA Section 4.7.5 describes the applicant's evaluation of the TLAA for reactor coolant pump flywheel fatigue crack growth. The LRA states that Technical Specification 5.5.7 requires an inspection program for the reactor coolant pump flywheels. Under this program, two of the flywheels receive either an ultrasonic or surface examination at 10-year intervals approximately, and all of the other flywheels receive these examinations at an interval not to exceed 20 years. Per the LRA, the fatigue crack growth analyses described in WCAP-14535A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination," dated November 1996, and WCAP-15666-A, "Extension of Reactor Coolant Pump Motor Flywheel Examination," dated October 2003, provide the bases for the 10- and 20-year inspection intervals, respectively.

**Issue**:

The reactor coolant pump flywheel fatigue crack growth analyses are based on 6,000 reactor coolant pump starts and stops. Based on a projection that the actual number of reactor coolant pump starts and stops will not exceed this number through 60 years of plant operation, the applicant stated that the analyses remain valid for the period of extended operation. However, the applicant did not provide the results from any of the past flywheel examinations. These results could invalidate the analyses if the examinations show an increase in flaw size or crack growth rate greater than calculated in WCAP-14535A and WCAP-15666-A.

**Request**:

Summarize the results of all of the past inservice inspections that were performed on the reactor coolant pump flywheel components. Include the examination dates and describe any flaws that were found. If flaws were detected, quantify any growth and provide a comparison against the crack growth rates from WCAP-14535A and WCAP-15666-A.

**Exelon Response:**

A review of the reactor coolant pump (RCP) motor flywheels surveillance records was conducted for the Byron and Braidwood units. Table 1 and Table 2, below, provide a summary of the results of these surveillance records for Byron and Braidwood, respectively. Only the most recent inspection results are provided in cases where there were no recordable indications identified in those inspections, since a finding of no recordable indications provides reasonable assurance that there would have been no indications found on earlier examinations. For motor flywheels with recordable indications, the previous examination result was also included in the tables to demonstrate that no significant change in the indication(s) has occurred during the time period between inspections. RCP motor serial numbers are provided since the installed location of some RCP motors have been changed as part of normal maintenance activities.

The RCP motor flywheels at Byron and Braidwood are examined periodically in accordance with Technical Specification 5.5.7, "Reactor Coolant Pump Flywheel Inspection Program." The RCP motor flywheel examination consists of either a qualified in-place ultrasonic testing (UT)

examination, or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheel at approximately 10-year intervals (for two (2) motor flywheels) or not to exceed 20-year intervals (for the other 16 motor flywheels). Rounded and linear indications have been detected during the RCP motor flywheel inspections. The rounded indications have been attributed to the act of removing and reassembling the motor flywheel resulting in nicks and gashes found during the inspection process. These rounded indications are not indicative and are not dispositioned as a linear crack. All recorded indications listed in Tables 1 and 2 were within the applicable WCAP-14535A and WCAP-15666-Aacceptance criteria and found to be acceptable. No discernible changes in recordable indications were noted during the subsequent examinations. There have been no indications of crack growth between inspections for the recorded indications.

During the review of the motor flywheel data for Byron, a difference was found between the 1995 and 2008 examination results for the 1A RCP motor flywheel. During the 1995 examination, three (3) linear indications had been noted of 5/32-inch, 1/8-inch, and 1/4-inch. However, in the 2008 examination, only one (1) linear indication of 5/32-inch was noted in the maintenance records. The 5/32-inch linear indication was at the same location, and exhibited no growth. This difference of two (2) indications (1/8-inch, and 1/4-inch) from the 1995 examination not being recorded or dispositioned in the 2008 records was entered into the corrective action program for further evaluation.

**Table 1: Byron Motor Flywheel Examinations**

| Current Position | Motor Serial Number | Exam Frequency | Exam Date | Exam Method | Exam Results | Comments |
|---|---|---|---|---|---|---|
| 1A | 1S84P740 | 20 Years | 4/2008 | Dye Penetrant | Recordable indications noted:<br>➢ One 5/32-inch linear indication<br>➢ Two 1/16-inch rounded indications | No indication of growth |
| | | | 11/1995 | Dye Penetrant | Recordable indications noted:<br>➢ One 5/32-inch, one 1/8-inch, and one 1/4-inch linear indications<br>➢ Three 1/16-inch and three 1/32-inch rounded indications | NA |
| 1B | 1S88P961 | 10 Years | 4/2005 | Ultrasonic & Dye Penetrant | No recordable indications | NA |
| 1C | 4S84P741 | 20 Years | 1/2006 | Dye Penetrant | No recordable indications | NA |
| 1D | 2S87P401 | 20 Years | 1/2012 | Dye Penetrant | No recordable indications | NA |
| 2A | 1S84P741 | 20 Years | 3/2004 | Dye Penetrant | No recordable indications | NA |
| 2B | 2S84P741 | 20 Years | 4/2010 | Dye Penetrant | No recordable indications | NA |
| 2C | 4S84P740 | 20 Years | 12/2012 | Dye Penetrant | Recordable indications noted:<br>➢ One 3/32-inch rounded indication | No indication of cracking |
| | | | 9/2003 | | No recordable indications | NA |
| 2D | 2S84P740 | 20 Years | 5/2005 | Dye Penetrant | Recordable indications noted:<br>➢ Three rounded indications from 7/16-inch to 5/8-inch | No indication of growth |
| | | | 2/1993 | | Recordable indications noted: One rounded indication 7/16-inch | NA |
| BYR Spare | 3S84P741 | 20 Years | 9/2002 | Dye Penetrant | No recordable indications | NA |

NA – Not Applicable

**Table 2: Braidwood Motor Flywheel Examinations**

| Current Position | Motor Serial Number | Exam Frequency | Exam Date | Exam Method | Exam Results | Comments |
|---|---|---|---|---|---|---|
| 1A | 1S87P400 | 20 Years | 10/2007 | Dye Penetrant | No recordable indications | NA |
| 1B | 2S87P400 | 20 Years | 4/2012 | Dye Penetrant | No recordable indications | NA |
| 1C | 3S87P400 | 20 Years | 4/2009 | Dye Penetrant | No recordable indications | NA |
| 1D | 4S87P400 | 20 Years | 10/2010 | Dye Penetrant | No recordable indications | NA |
| 2A | 1S87P401 | 20 Years | 10/2009 | Dye Penetrant | No recordable indications | NA |
| 2B | 3S84P740 | 20 Years | 4/2011 | Dye Penetrant | No recordable indications | NA |
| 2C | 3S87P401 | 20 Years | 11/2003 | Dye Penetrant | Recordable indications noted:<br>➢ Four linear indications from 1/16-inch to 3/16-inch<br>➢ Six rounded indications from 1/32-inch to 3/8-inch | No indication of growth |
| | | | 10/94 | | Recordable indications noted:<br>➢ Four linear indications from1/16-inch to 3/16-inch<br>➢ Six rounded indications from 1/32-inch to 3/8-inch | NA |
| 2D | 4S87P401 | 20 Years | 10/2012 | Dye Penetrant | No recordable indications | NA |
| BRW Spare | 4S88P961 | 10 Years | 6/2010 | Dye Penetrant | No recordable indications | NA |

NA – Not Applicable

**RAI 4.7.5-2,** Reactor coolant pump flywheel fatigue crack growth TLAA and [updated final safety analysis report (UFSAR)] summary (067)

**Applicability**: Byron and Braidwood

**Background**:

The reactor coolant pump flywheel fatigue crack growth TLAA, described in LRA Section 4.7.5, covers two separate analyses. One analysis, based on WCAP-14535A, establishes an approximate 10-year inspection frequency for two reactor coolant pump flywheels. The other analysis, based on WCAP-15666-A, establishes a 20-year maximum inspection frequency for all of the other flywheels.

**Issue**:

LRA Section A.4.7.5 provides the UFSAR supplement summary description for the reactor coolant pump flywheel fatigue crack growth TLAA. However, the summary description does not:

(a) indicate that the TLAA supports the basis for continuation of the 20-year inspection frequency (it only mentions that it supports continuation of the 10-year inspection frequency), and

(b) identify each reactor coolant pump and specify which WCAP report and corresponding inspection frequency apply to that pump.

Thus, it is not evident as to which of the two WCAP reports apply to the specific reactor coolant pump flywheels at Bryon Units 1 and 2 and Braidwood Units 1 and 2.

**Request**:

Revise LRA Section A.4.7.5 to clearly identify each of the reactor coolant pump motor flywheels at Bryon Units 1 and 2 and Braidwood Units 1 and 2 and specify which WCAP report and corresponding inspection frequency apply to each pump motor's flywheel.

**Exelon Response:**

The reactor coolant pump (RCP) motor flywheel fatigue crack growth TLAA, described in LRA Section 4.7.5, refers to two separate analyses, WCAP-14535A and WCAP-15666-A. There are a total of sixteen reactor coolant motor flywheels installed at Byron and Braidwood Units 1 and 2. Two (2) additional motor flywheels are available as spares that are rotated into service in accordance with the maintenance schedule for the motors.

The first analysis, WCAP-14535A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination", establishes a ten-year inspection frequency for two RCP motor flywheels, which are integral elements of the RCP motors that were originally designed and built for a different station. This WCAP report applies only to the two reactor coolant pump motor flywheels with serial numbers 4S88P961 and 1S88P961. The NRC approved the 10-year surveillance interval of these motor flywheels in the safety evaluation report for the Technical Specification amendments in 2010 (Accession Number ML102510495). While these two (2)

RCP motor flywheel combinations can be utilized in any reactor coolant pump position at either Braidwood or Byron Stations, these two motor flywheels have different surveillance intervals than the Braidwood and Byron Station RCP motor flywheels that were evaluated in WCAP-15666-A, “Extension of Reactor Coolant Pump Motor Flywheel Examination.” The second analysis, WCAP-15666-A, establishes an examination interval not to exceed 20-years maximum inspection frequency for the other sixteen motor flywheels.

LRA Sections A.4.7.5 and 4.7.5 are revised to reflect the changes discussed above, and are included in Enclosure D.

**RAI 3.2.1.20-1,** Aging Management for Venturi Flow Meters (101)

**Applicability:** Byron and Braidwood

**Background**:

EPRI Report TR-112118, "Nuclear Feedwater Flow Measurement Application Guide," July 1999, indicates that venturi flow meters used to calculate feedwater flow rates in nuclear power plants are susceptible to aging degradation such as fouling and loss of material due to erosion and corrosion (including defouling), all of which can cause flow measurement errors. In its review of LRA Item 3.2.1-20, the staff also noted that LRA Tables 3.2.2-3 and 3.2.2-4 address aging management of loss of material in stainless steel restricting orifices using the One-Time Inspection Program and the Water Chemistry Program. However, the LRA does not address any AMR item to manage aging for venturi flow meters.

During the audit, the staff noted the applicant's operating experience described in AR 00748581, "Feedwater Venturi Fouling Indication," dated March 12, 2008, which states that during normal thermal performance monitoring activities, some signs of feedwater flow venturi fouling were observed for Braidwood Unit 2 venturis.

**Issue**:

Flow measurement and calculation errors associated with aging degradation of venturi flow meters can cause safety-related issues such as overpower conditions and can accelerate aging effects of piping and piping components through those overpower conditions. However, the LRA does not describe how the applicant will manage fouling and loss of material for feedwater venturi flow meters.

**Request**:

Describe how the aging effects of fouling and loss of material for feedwater venturi flow meters will be managed, and revise the LRA consistent with the response. Alternatively, provide adequate justification why managing of these aging effects is not required.

**Exelon Response:**

Byron and Braidwood Stations currently utilize ultrasonic feedwater measurement technology (LEFM) in determining feedwater flow rates for Core Thermal Power (CTP) calculations. The feedwater venturis remain in place as a back-up flow measurement system in the event the LEFM are not in service and to provide active input into the steam generator level control system (SGLCS). A 3-element SGLCS is used at rated power where changes in either steam flow or feedwater flow are used to anticipate a change in steam generator water level to provide for more precise level control. The venturis are used briefly during start-ups at low power levels and following refueling outages to support calorimetric analysis to validate the reactor coolant flow rates for each of the four flow loops to demonstrate Technical Specification requirements are being satisfied.

The nonsafety-related feedwater venturi housings (categorized as piping components) are in the scope of license renewal for 10 CFR 54.4(a)(2) (functional support) as part of the Engineered

Safety Feature to provide redundant isolation of the feedwater supply to each steam generator. The nonsafety-related venturis themselves do not have a license renewal intended function. They do not provide an input into the Reactor Trip System nor are they designed to restrict feedwater flow in the event of a line break. Therefore, there are no additional license renewal intended functions for the feedwater venturi assembly.

The feedwater venturis support a non-license renewal function in that they measure flow. To assure accuracy, venturi readings are continuously compared to the outputs of the LEFM system. During normal LEFM system operations, at five second intervals, the calorimetric application calculates a new set of multipliers for each venturi output. In the event of a LEFM system failure, time averaged multipliers are applied to the venturi outputs. Additionally, this function is managed through Technical Specifications, requiring inspections of the venturis for fouling and loss of material on an 18-month frequency. Therefore, no additional requirements have been identified to manage fouling or loss of material for the feedwater venturis.

**RAI 3.1.1.80-1:** Aging Management for Piping and Piping Components of the Reactor Coolant System (101)

**Applicability:** Byron and Braidwood

**Background**:

LRA Item 3.1.1-80 addresses cracking due to stress corrosion cracking (SCC) for stainless steel pressurizer relief tank and associated components (non-ASME Section XI components) exposed to treated borated water greater than 140 °F. LRA Item 3.1.1-80 also indicates that the applicant uses the One-Time Inspection Program and Water Chemistry Program to manage this aging effect for the none-ASME Section XI components.

LRA Table 3.1.2-1 (Page 3.1-57) indicates that the applicant also uses LRA Item 3.1.1-80 to manage cracking due to SCC for stainless steel piping, piping components, and piping elements of the RCS, which are exposed to reactor coolant. These components are associated with generic note C, indicating that these components are different from those which are evaluated in the Generic Aging Lessons Learned (GALL) Report, but applicant's aging management is consistent with the GALL Report for material, environment, aging effect, and aging management program. However, the staff noted that the LRA does not clearly indicate whether these are ASME Code Class components.

**Issue**:

The LRA does not address why periodic inspections (e.g., ASME Code Section XI examinations) are not used to manage cracking for these piping, piping elements and piping components exposed to reactor coolant.

**Request**:

1. Clarify whether the subject piping, piping components and piping elements of the reactor coolant system are ASME Code Class components. As part of the response, describe the names and locations of the components in order to demonstrate that the ASME Code examination requirements are not applicable for these components.

2. If these are ASME Code Class components, justify why periodic inspections (e.g., ASME Code Section XI examinations) are not used to manage cracking for the components which are exposed to reactor coolant.

**Exelon Response:**

1. The piping, piping components and piping elements attached to the reactor coolant system are ASME Code Class 2 components. These piping and connections are not required to be surface or volumetrically examined in accordance with the ASME Code requirements, since they are less than or equal to 1.5-inch NPS. The line item (IV.C2.RP-383, 3.1.1-80) included the component type for the piping and instrumentation tubing connections on the Reactor Coolant System piping. The piping ($\leq$ 1.5-inch) and instrumentation tubing is ASME Code Class 2 and includes the following components:

- Reactor coolant flow transmitters (0.75-inch)
- Sampling system piping (0.375-inch to 0.75-inch)
- Reactor vessel level (refueling) transmitters (0.75-inch)
- Pressurizer level transmitters (0.75-inch)
- Pressurizer pressure transmitters (0.75-inch)
- Pressurizer spray valve bypass piping (0.75-inch)
- Reactor Coolant wide range pressure transmitters (0.75-inch)
- Safety valve loop seal drain piping (0.75-inch)
- RCP seal leak-off bypass connections (0.75-inch)
- RCP seal injection and #1 seal leak-off connections and drains (0.75-inch to 1.5 -inch)
- RCP #2 and #3 seal leak-off connections (0.75-inch to 1.0-inch)
- Residual heat removal suction line drain valves (0.75-inch)
- Safety injection cold leg flow transmitters (0.75-inch)
- Safety injection hot leg test piping (0.75-inch)
- Safety injection accumulator cross-connect piping (0.75-inch)
- Reactor Coolant – CVC mini-flow valve pressure transmitters (0.75-inch)
- Reactor Coolant loop bypass flow transmitters (0.75-inch)

2. The piping and instrumentation tubing components for the miscellaneous small connections to the Reactor Coolant System are classified as ASME Code Class 2. Since they are less than or equal to 1.5-inch, the piping and instrumentation tubing components are not required to be surface or volumetrically examined in accordance with the ASME Code requirements. However, these ASME Code Class 2 components are included as part of the pressure testing (VT-2) for the reactor coolant system boundary. Since a VT-2 examination can only detect cracking after it occurs, the Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20) aging management programs were credited for management of cracking as opposed to the ASME Code required VT-2 examination, which is consistent with NUREG-1801. An operating experience review was performed for the Byron and Braidwood units, and no evidence of cracking due to vibrations or stress corrosion cracking was found for the piping and instrumentation tubing components attached to the Reactor Coolant System.

**RAI 3.1.1.81-1:** Aging Management for Reactor Coolant Pump Thermal Barrier Heat Exchanger Tubes (101)

**Applicability:** Byron and Braidwood

**Background**:

LRA Item 3.1.1-81 addresses cracking due to SCC for stainless steel pressurizer spray head exposed to reactor coolant, which is managed by the One-time Inspection Program and Water Chemistry Program. As described in LRA Table 3.1.2-1, the applicant uses LRA Item 3.1.1-81 to manage cracking due to SCC for tubes of reactor coolant pump thermal barrier heat exchangers which are exposed to reactor coolant. The LRA does not identify any periodic inspection activities to manage cracking for these heat exchanger tubes.

In addition, the staff noted that UFSAR Section 11.5.2.3.2, "Component Cooling Water Monitors," indicates that applicant's radiation detectors continuously monitor the component cooling system for leakage of reactor coolant from the reactor coolant system and/or the residual heat removal system.

**Issue**:

The reactor coolant pump thermal barrier heat exchanger tubes form the pressure boundary between the component cooling and reactor coolant systems. However, the LRA does not identify any periodic inspections to manage cracking for these heat exchanger tubes. In addition, the LRA does not address whether applicant's operating experience, including the component cooling water monitoring activity of the UFSAR, confirms that cracking is not occurring in the heat exchanger tubes.

**Request**:

1. Justify why the LRA does not identify any periodic inspections to manage cracking for the RCP thermal barrier heat exchanger tubes. Alternatively, identify periodic inspections to manage cracking for these components. As part of the response, confirm whether or not the heat exchanger tubes are ASME Code Class 1 components.

2. Clarify whether applicant's operating experience confirms that cracking is not occurring in the heat exchanger tubes.

**Exelon Response:**

1. The reactor coolant pump thermal barrier heat exchanger has reactor coolant (seal injection flow) on the outside of the tubes and component cooling (closed-cycle cooling water) on the inside of the tubes. This heat exchanger consists of only concentric tubes around the pump shaft (i.e., no shell, tube sheet, tube side components), and is integral to the pump casing assembly. The reactor coolant that is flowing on the outside of the stainless steel tubes is greater than 140 ˚F and has oxygen controlled to less than 5 ppb dissolved oxygen. The component cooling water side has corrosion inhibitors to limit the corrosion inside the tubes. The reactor coolant pump thermal barrier heat exchanger is an ASME Code Class 1 component.

Direct inspection of the thermal barrier heat exchanger tubes is not feasible on the Byron and Braidwood reactor coolant pumps. The entire thermal barrier, including the heat exchanger subassembly, is a fully welded fabrication. Direct inspection is only possible by destructive disassembly.

Since periodic inspection of the thermal barrier heat exchanger tubes is not feasible, the use of a GALL line item to determine the aging effects for a different component but similar materials and environment is appropriate. The Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20) aging management programs together with the existing design features discussed below are used to justify that aging of the tubes for potential cracking will be adequately managed during the period of extended operation without periodic inspections. The use of these aging management programs is consistent with NUREG-1801.

There are several indications that provide continuous monitoring of the reactor coolant pump thermal barrier heat exchanger. Monitoring for cracking of the thermal barrier heat exchanger tubes is performed by radiation monitors, which would detect an increase in radioactivity in the Component Cooling System, and the component cooling surge tank level alarms which would detect an unexpected increase in water level. Also, high component cooling flow conditions are monitored on the outlet lines of the heat exchangers to detect high flow which automatically initiate signals to isolate flow with the isolation valves inside containment. A high temperature alarm on the thermal barrier outlet piping is also installed to detect anomalies (e.g., increasing component cooling temperature, outlet flow, radiation level) with the thermal barrier heat exchanger. Station operating procedures provide appropriate actions should any of the above conditions occur. In addition to the above, the Closed Treated Water Systems (B.2.1.12) aging management program is a mitigative program which will also manage the aging effects of the inside of the heat exchanger tubes.

Based on the above there is reasonable assurance that the Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20) aging management programs together with the existing design features discussed above will be adequate to detect and manage the aging effect of cracking during the period of extended operation.

2. A review was conducted of the operating experience associated with the component cooling sample results for the past five (5) years of operation. There have been no indications of reactor coolant pump thermal barrier tube leaks based on the radioactivity level of the component cooling samples. The radioactivity level increase would be one of the first indications of a tube leak similar to the monitoring of the steam generator tube leakage on the secondary side chemistry samples. Therefore, the operating experience at both Byron and Braidwood stations provides reasonable assurance that cracking is not occurring in the thermal barrier heat exchangers.

**RAI 4.7.4-1:** TLAA for Flaws in RHR Heat Exchanger Nozzles (111)

**<u>Applicability</u>:** Byron and Braidwood

**<u>Background</u>**:

LRA Section 4.7.4 addresses applicant's facture mechanics analysis for the tube side inlet and outlet nozzles of residual heat removal (RHR) heat exchangers. The LRA identifies this fracture mechanics analysis as a TLAA. The LRA states that indications were detected in Braidwood 2A and 2B RHR heat exchangers during ultrasonic examinations in 1991 and some of these indications exceeded the acceptance standards of the 1983 Edition through the Summer 1983 Addenda of ASME Section XI, Subarticle IWB-3500.

The LRA also states that these flaws were subjected to further evaluation in accordance with ASME Section XI, Subarticle IWB-3600. The LRA further states that even though the RHR heat exchangers are ASME Code Class 2 components, the applicant performed an ASME Code Class 1 fracture mechanics analysis and this evaluation demonstrated that continued operation of Braidwood Unit 2 RHR heat exchangers was acceptable even with these flaws.

In addition, the LRA states that subsequently, ultrasonic examinations were performed on all the RHR heat exchanger tube side inlet and outlet nozzles at Byron and Braidwood Stations, Units 1 and 2. The LRA states that any additional indications exceeding the IWB-3500 acceptance standards were dispositioned with the results of the fracture mechanics analysis. The LRA also states that WCAP-13454, "Fracture Mechanics Evaluation, Byron and Braidwood, Units 1 and 2, Residual Heat Exchanger Tube Side Inlet and Outlet Nozzles," August 1992 (Proprietary), and WCAP-13455, "Fracture Mechanics Evaluation, Byron and Braidwood, Units 1 and 2, Residual Heat Exchanger Tube Side Inlet and Outlet Nozzles," August 1992 (Non-proprietary, ADAMS Accession No. 9208280207), were submitted to the NRC on August 25, 1992 to present the original fracture mechanics methodology for dispositioning the indications which were found at Byron and Braidwood.

In its review of LRA Section 4.7.4, the staff also noted that a relief request by the applicant indicated that an ASME Section XI repair by excavation was completed on the unacceptable flaws of the Braidwood Unit 2 RHR heat exchanger nozzle-to-vessel welds ("Relief from Inservice Inspection Requirements for Residual Heat Removal Heat Exchanger Nozzle-to-Vessel Welds," dated December 12, 1995, ADAMS Accession No. 951219036). The staff also noted that this reference stated that the Braidwood, Unit 2 flaws were fabrication flaws, slag, incomplete fusion and excess porosity. The staff further noted that the above reference did not identify any other unacceptable flaws of the Byron and Braidwood RHR heat exchanger nozzles.

**<u>Issue</u>**:

It is unclear to the staff whether there are flaws currently in the nozzles that exceed the acceptance standards of ASME Code Section XI IWB-3500. It is also unclear to the staff whether the fracture mechanics analysis is relied upon to support: (a) continued service with existing flaws in these nozzles, or (b) applicant's relief request for an alternative to the ASME Code inservice inspection method for these nozzles (e.g., performing VT-2 visual examination in

place of ultrasonic testing). Finally, the staff needs additional information regarding the existing flaws and flaw growth analysis.

**Request**:

1. Clarify whether there are flaws currently in the Byron and Braidwood RHR heat exchanger nozzles that exceed the acceptance standards of ASME Code Section XI IWB-3500.

2. Clarify whether the fracture mechanics analysis is relied on to support: (a) continued service of the heat exchanger nozzles with existing flaws, or (b) applicant's relief request for an alternative to the ASME Code inservice inspection method for these nozzles (e.g., performing VT-2 visual examination in place of ultrasonic testing).

   The staff notes that relief requests for inservice inspections are only valid for the current inservice inspection ten-year interval and are required to be resubmitted for each interval for the period of extended operation if desired. Given this fact, if the fracture mechanics analysis is relied on to support the use of an alternate inspection method under a relief request process, clarify why the relief request process is not identified as part of the 10 CFR 54.21(c)(1)(iii) aging management basis in conjunction with the fracture mechanics analysis.

3. Provide the following information for the applicant's fracture mechanics analysis: (a) current flaw sizes (i.e., length and depth), orientations (i.e., circumferential and axial) and locations based on the most recent inspection results in comparison with nozzle dimensions, and (b) projected flaw sizes at the end of the period of extended operation. As an alternative to (a) and (b), if a bounding-case analysis is applicable to each nozzle, provide the maximum current flaw size and maximum projected flaw size with the associated orientation and location which bound the other flaws for each nozzle. (c) In addition to the information for (a) and (b), describe the acceptance criteria for the flaws and when the most recent volumetric examination was performed on each nozzle. As part of this response, provide the relevant transient names and projected numbers of transient cycles for the fracture mechanics analysis.

**Exelon Response:**

1. Byron and Braidwood Unit 1 and 2 Residual Heat Removal (RHR) Heat Exchanger tube side inlet and outlet nozzle welds currently contain flaws that exceed the acceptance standards of ASME Section XI, Subarticle IWB-3500, 1983 Edition, through Summer 1983 Addenda. These flaws, which were found between 1991 and 1994, were determined to be fabrication flaws. Even though the RHR Heat Exchangers are ASME Class 2 components, a Class 1 fracture mechanics analysis, which met the requirements of ASME Section XI, Subarticle IWB-3600, was performed on these flaws. The flaws, which satisfied ASME Section XI, Subarticle IWB-3640 requirements, were determined to be acceptable and remain in service today. Only flaws on the Braidwood Unit 2 "B" heat exchanger outlet nozzle did not satisfy ASME Section XI, Subarticle IWB-3640 requirements and were repaired in 1994.

The fracture mechanics analysis supporting the flaw evaluations were submitted to the NRC for review. The NRC reviewed and approved the analysis in a letter dated February 3, 1995, “Residual Heat Exchanger Nozzle Welds, Byron Station, Unit 1 and 2, and Braidwood Station, Units 1 and 2 (TAC Numbers M90894, M90895, M91408, and M90840),” (Accession Number 9502130037).

2. The fracture mechanics analysis of the flaws is relied on to support continued service of the heat exchanger nozzles.

   ASME Code Case N-706-1 was endorsed as “acceptable” (not “conditional”) by the NRC in January 2007 as documented in Regulatory Guide 1.147, Rev 16, “Inservice Inspection Code Case Acceptability ASME Section XI, Division 1.” As such, the submittal for a relief request to use this code case is not required, and the relief request process is not applicable.

   ASME Code Case N-706-1 provides relief from the requirement to perform an ultrasonic test (UT) examination of welds on PWR stainless steel regenerative and residual heat exchangers. The code case allows VT-2 inspections of welds in lieu of the UT examination, provided the welds have been volumetrically examined at least once. Since the Byron and Braidwood RHR Heat Exchangers welds have all been volumetrically examined with UT and dispositioned in accordance with the fracture mechanics analysis, the use of the code case to perform VT-2 examinations of the welds instead of UT examinations is permissible. Therefore, the use of ASME Code Case N-706-1 relies upon the fracture mechanics analysis.

3. The fracture mechanics analysis provides a bounding case analysis which is applicable to each residual heat removal (RHR) heat exchanger tube side inlet and outlet nozzle. Flaw number three (3) on the Braidwood Unit 2 “2B” RHR Heat Exchanger inlet nozzle bounds all flaws that were dispositioned as acceptable for continued service. This flaw has an “as found” crack depth of 0.300 inches in a portion of the nozzle with a wall thickness of 0.526 inches. Applying the fatigue flaw crack depth growth of 0.001 inches, after an additional 200 cycles, results in a projected crack depth of 0.301 inches and the percentage of flaw depth to nozzle wall thickness would be 57.2%, which meets the acceptance criterion. The fracture mechanics analysis concludes that for each inlet and outlet nozzle, the appropriate acceptance criterion, in accordance with ASME IWB-3460, is a maximum allowed flaw depth of 60% of the nozzle wall thickness.

   The most recent volumetric examinations performed on each nozzle are as follows:

   - Braidwood Unit 1, 1RH02AA and 1RH02AB inlet and outlet nozzles,1992,
   - Braidwood Unit 2, 2RH02AA and 2RH02AB inlet and outlet nozzles,1994,
   - Byron Unit 1, 1RH02AA and 1RH02AB inlet and outlet nozzles, 1993, and
   - Byron Unit 2, 2RH02AA and 2RH02AB inlet and outlet nozzles, 1992.

   The flaw evaluation methodology in the analysis includes loading conditions for thermal expansion, internal pressure, deadweight, and operating basis and safe shutdown earthquakes for the residual heat removal heat exchanger inlet and outlet nozzles. The flaw growth analysis considers fatigue, and crack growth is calculated based on ASME Section XI Appendix C (1989 Addenda). Crack growths were calculated from applied stresses

during transients and residual stresses. The RHR Heat Exchangers are only used when the Reactor Coolant System (RCS) is cooled down to Cold Shutdown and Refueling, as the RHR system is placed into service, and later during RCS heatup until the RHR system is taken out of service. The crack growth analysis assumed 200 cycles corresponding to 200 Plant Heatups and Plant Cooldowns (transients 1 and 2 on LRA Tables 4.3.1-1 and 4.3.1-4 for Byron and Braidwood, respectively) over the life of the plant. Based on the assumed cycles, the analysis results in a fatigue crack depth growth of less than 0.001 inches. Therefore, the projected crack depth after 200 cycles is calculated by adding 0.001 inches to the “as-found” crack depth. The maximum number of Plant Heatups and Plant Cooldowns (transients 1 and 2 on LRA Tables 4.3.1-1 and 4.3.1-4) projected for 60 years is 117 on Byron Unit 1, which bounds all four units.

**RAI 4.1-1,** Absence of a TLAA for Flow-Induced Vibrations (058)

**Applicability**: Byron and Braidwood

**Background**:

LRA Table 4.1-1 identifies that the Byron and Braidwood CLBs do not include any flow-induced vibration analyses for reactor vessel internal (RVI) components that conform to the definition of a TLAA in 10 CFR 54.3(a) or would need to be identified as TLAAs in accordance with the requirement in 10 CFR 54.21(c)(1). Consistent with this basis, LRA Section 4.3.5 states that the applicable RVI flow-induced vibration analyses in the CLB are based on stress ranges that are below the ASME Section III fatigue endurance limit of $10^{11}$ cycles. LRA Section 4.3.5 states that the number of the stress range cycles is not limited over the current operating life and, therefore, the analyses are not based on any time-dependent assumptions defined by the current operating terms and are not classified as TLAAs in accordance with 10 CFR 54.3(a), Criterion 3.

UFSAR Section 3.9 provides relevant design basis information. UFSAR Section 3.9.5.2 states that the design of the RVI components is based on the design basis loading conditions for normal operating, upset, emergency, and faulted condition transients that are listed on UFSAR pages 3.9-96 and 3.9-97. The UFSAR indicates that vibratory loads (including those that would occur during postulated operational basis earthquake conditions) are listed as normal operating condition loads for the RVI components. In addition, the UFSAR states that the design basis relies on previous RVI flow-induced vibration models and tests that were performed at the Indian Point Unit 2 and Trojan nuclear power plants and that form the basis for assessing flow-induced vibrations of the RVI components at the Byron and Braidwood Stations. The UFSAR establishes that these models and tests are summarized in the following Westinghouse technical reports (TR):

- WCAP-8317-A, "Prediction of the Flow-Induced Vibration of Reactor Internals by Scale Model Tests," July 1975 (a report that is applicable to Indian Point Unit 2)

- WCAP-8780, "Verifications of Neutron Pad and 17 X 17 Guide Tube Designs by Preoperational Tests on the Trojan Unit 1 Plant," May 1976

**Issue**:

The applicant's basis for claiming that the treatment of RVI flow-induced vibrations does not need to be within the scope of a TLAA is based on the position that the vibratory stress loads for the RVI components are lower than the stress endurance limits for inducing fatigue in components. The staff finds this TLAA-identification basis is acceptable if the stated treatment of RVI vibratory loads was established in either Westinghouse TR No. WCAP-8317-A or TR No. WCAP- 8780 as approved reports for the current design basis. However, the staff cannot determine, with certainty, whether this type of technical basis was established in either of the referenced WCAP reports.

**Request**:

Clarify whether TR No. WCAP-8317-A or TR No. WCAP-8780 establishes the basis in the CLB for concluding that the RVI vibration stress loads are lower than the endurance limit for initiation of high-cycle fatigue. If not, identify and justify the document in the CLB that establishes and is relied upon for this design basis position.

**Exelon Response:**

Both WCAP-8317-A and WCAP-8780 establish the basis for the reactor vessel internals (RVI) flow induced vibration analysis in the current licensing basis as discussed in UFSAR Section 3.9.2.3. The initial basis for high-cycle vibratory analyses and scale model testing is provided in WCAP-8317-A. The conclusions of WCAP-8317-A were confirmed by instrumented plant (Trojan Unit 1) hot functional test results as presented in WCAP-8780 which demonstrated that the stress levels due to flow induced vibration on the RVI critical structural components were well below the endurance limit. The endurance limit is the stress range below which the material will not experience a fatigue failure.

**RAI 4.1-2,** Absence of a TLAA for Metal Corrosion Allowances (058)

**Applicability**: Byron and Braidwood

**Background**:

LRA Table 4.1-1 identifies that the Byron/Braidwood CLBs do not include any component-specific metal corrosion allowance analyses that conform to the definition of a TLAA in 10 CFR 54.3(a) or would need to be identified as TLAAs in accordance with 10 CFR 54.21(c)(1).

**Issue**:

The UFSAR does make reference to one metal corrosion allowance report. Specifically, UFSAR Section 5.4.2.5.4 refers to Babcock and Wilcox (B&W) Report No. 222-7720-PR05, Revision 3, "Replacement Steam Generators Secondary Side Corrosion Allowance Values for Design of Analysis." However, the UFSAR does not specifically indicate whether this report is being relied upon as part of the CLBs or design bases for the Byron and Braidwood reactor units.

**Request**:

Clarify whether B&W Report No. 222-7720-PR05, Revision 3, is relied upon for the CLBs or current design bases of the Byron and Braidwood reactor units. If the report is relied upon for the CLB or current design basis, assess the contents of the report against the six criteria in 10 CFR 54.3(a) for defining an analysis as a TLAA and justify why the metal corrosion allowance analysis in this report would not need to be identified as a TLAA for the secondary sides of the steam generators (SGs) in the Byron and Braidwood units.

**Exelon Response:**

B&W Report No. 222-7720-PR05, "Replacement Steam Generators Secondary Side Corrosion Allowance Values for Design and Analysis", is relied upon for the CLB's for Byron and Braidwood Unit 1 Steam Generators, and it is referenced in the UFSAR, Section 5.4.2.5.4. The scope of the report is to provide the general corrosion losses, during multiple chemical cleaning activities, and normal operation, to be used in design and analysis of steam generator secondary side surfaces. The report is not a TLAA because it does not meet Criterion 5 ("Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in 10 CFR 54.4(b)") from 10 CFR 54.3.

The report provides the appropriate material corrosion allowance for use in the design and analysis, but does not provide any basis for the capability of the steam generators to perform their intended functions. Based on subcomponent material and location in the steam generator, it utilizes industry and vendor guidance and experience to determine an estimated corrosion allowance. The corrosion allowance estimate is based on the loss of material associated with chemical cleaning and the combination of the effects of general corrosion, and flow accelerated corrosion.

The corrosion allowance from the B&W report is used in UFSAR Section 5.4.2.5.4 to support the review of the tube wall thickness margin. The B&W report provides an estimated corrosion allowance total of 0.0008 inches. The total estimated corrosion allowance is the sum of 0.00025 inches for the primary tube side and 0.00055 inches for the secondary tube side. The UFSAR concludes that there is a 0.0122 inch margin to the required minimum tube wall thickness even after subtracting the corrosion allowance of 0.0008 inches from the minimum fabricated tube wall thickness (0.036 inches). Therefore, the estimated corrosion allowance is insignificant with respect to margin, and if assumed to occur during 40 year operating license period, is equivalent to a lifetime corrosion margin of a factor of over 15 (0.0122/0.0008) or about 600 years. The example in the UFSAR does not support a conclusion of the capability of the tubes to perform their intended function, but demonstrates an insignificant effect on margin when considering this estimated general corrosion consideration. Therefore, when evaluating the CLB analysis discussed in the UFSAR Section 5.4.2.5.4 for consideration of a potential TLAA, the B&W report input to this analysis did not satisfy Criterion 5 from the 10 CFR 54.3 definition for a TLAA.

Similar to the UFSAR example above, design analyses for the steam generator secondary components utilize the material corrosion allowances contained in this report as inputs to provide margin when meeting design requirements. No analyses were found which assessed the degradation or aging of the secondary components, where the estimated corrosion allowances contained in this report were used as limits to provide a conclusion the component continued to meet its design requirements. Therefore, Criterion 5 from the 10 CFR 54.3 definition for a TLAA is not satisfied.

The report provides corrosion and erosion estimates for use in design and analysis of steam generator secondary components, but does not present limits for the amount of corrosion. The analysis does not provide the basis for the capability of the steam generators to perform their intended functions and, therefore, does not satisfy Criterion 5 of the 10 CFR 54.3 definition for a Time Limited Aging Analysis. It also does not satisfy the guidance for Criterion 5 provided in NUREG-1800, Section 4.1, “Identification of Time-Limited Aging Analyses”. Therefore, the B&W report is not an example of a plant specific metal corrosion allowance TLAA listed in NUREG-1800, Table 4.1-3,”Examples of Potential Plant Specific TLAAs”. As a result, Table 4.1-1 of the LRA appropriately documents that the plant specific metal corrosion allowance TLAA does not apply to Byron and Braidwood Stations.

**Enclosure C**

Westinghouse Affidavit supporting Proprietary Treatment

of the following Set 10 RAI Responses

RAI 4.3.1-1
RAI 4.3.1-3
RAI 4.3.4-1
RAI 4.3.4-2
RAI 4.3.4-3
RAI 4.3.4-4
RAI 4.3.4-5
RAI 4.3.4-6
RAI 4.3.4-7
RAI 4.3.7-1

Note: The responses are contained in Enclosure B

Westinghouse

Westinghouse Electric Company
Engineering, Equipment and Major Projects
1000 Westinghouse Drive
Cranberry Township, Pennsylvania 16066
USA

U.S. Nuclear Regulatory Commission
Document Control Desk
11555 Rockville Pike
Rockville, MD 20852

Direct tel: (412) 374-4643
Direct fax: (724) 720-0754
e-mail: greshaja@westinghouse.com
Proj letter:

CAW-14-3934

March 28, 2014

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: "Byron and Braidwood Units 1 and 2 License Renewal: NRC Request for Additional Information Proprietary Class 2 Responses," (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-14-3934 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The Affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

The subject document was prepared and classified as Westinghouse Proprietary Class 2. Westinghouse requests that the RAI responses in the document attachment be considered proprietary in their entirety. As such, a non-proprietary version will not be issued.

Accordingly, this letter authorizes the utilization of the accompanying Affidavit by Exelon.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse Affidavit should reference CAW-14-3934, and should be addressed to James A. Gresham, Manager, Regulatory Compliance, Westinghouse Electric Company, Suite 310, 1000 Westinghouse Drive, Cranberry Township, Pennsylvania 16066.

Very truly yours,

J A Gresham

James A. Gresham, Manager
Regulatory Compliance

Enclosures

# AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF BUTLER:

Before me, the undersigned authority, personally appeared James A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

J A Gresham

James A. Gresham, Manager
Regulatory Compliance

Sworn to and subscribed before me
this 28th day of March 2014

Anne M. Stegman

Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Anne M. Stegman, Notary Public
Unity Twp., Westmoreland County
My Commission Expires Aug. 7, 2016
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

(1) I am Manager, Regulatory Compliance, in Engineering, Equipment and Major Projects, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse Application for Withholding Proprietary Information from Public Disclosure accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitute Westinghouse policy and provide the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of

Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

(iii) There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iv) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(v) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(vi) The proprietary information sought to be withheld in this submittal is that set of RAI responses which is contained in LTR-PAFM-14-31 Attachment A, "Byron and Braidwood Units 1 and 2 License Renewal: NRC Request for Additional Information Proprietary Class 2 Responses" (Proprietary), for submittal to the Commission, being transmitted by Exelon letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted by Westinghouse is that associated with Responses to NRC Requests for Additional Information, (Set 10), and may be used only for that purpose.

(a) This information is part of that which will enable Westinghouse to:

(i) Perform Environmental Fatigue Screening

(ii) Utilize the Westinghouse Reference Fatigue Database

(iii) Utilize Plant Operating Data in lieu of Design Transient Data

(iv) Perform Environmental Fatigue Evaluations

(b) Further this information has substantial commercial value as follows:

(i) Westinghouse plans to sell the use of similar information to its customers for the purpose of performing required environmental fatigue screening and fatigue evaluations, and utilizing plant operating data in lieu of design transient data.

(ii) The information requested to be withheld reveals the distinguishing aspects of a methodology which was developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar environmental fatigue-related evaluations and plant operating data utilization, and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

## PROPRIETARY INFORMATION NOTICE

Transmitted herewith is the proprietary version of a document furnished to the NRC in connection with requests for generic and/or plant-specific review and approval. The document is to be considered proprietary in its entirety.