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

October 1, 2008

Mr. Charles G. Pardee
President and Chief Nuclear Officer
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BYRON STATION, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENTS RE: REVISION TO TECHNICAL SPECIFICATIONS FOR THE STEAM GENERATOR PROGRAM (TAC NOS. MD9018 AND MD9019)

Dear Mr. Pardee:

The U.S. Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment No. 158 to Facility Operating License No. NPF-37 and Amendment No. 158 to Facility Operating License No. NPF-66 for the Byron Station (Byron), Unit Nos. 1 and 2, respectively. The amendments are in response to your application dated June 17, 2008.

The amendments revise Technical Specification (TS) 5.5.9, "Steam Generator (SG) Program," and TS 5.6.9, "Steam Generator (SG) Tube Inspection Report." For TS 5.5.9, the amendments incorporate a one-cycle interim alternate repair criteria in the provisions for SG tube repair criteria during Byron, Unit No. 2, refueling outage 14 and the subsequent operating cycle. For TS 5.6.9, the amendments revise the current reporting requirements. These changes only affect Byron, Unit No. 2; however, this action is docketed for both Byron units because the TS are common to both units.

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

Marshall J. David, Senior Project Manager
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. STN 50-454 and STN 50-455

Enclosures:
1. Amendment No. 158 to NPF-37
2. Amendment No. 158 to NPF-66
3. Safety Evaluation

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

EXELON GENERATION COMPANY, LLC

DOCKET NO. STN 50-454

BYRON STATION, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 158
License No. NPF-37

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Exelon Generation Company, LLC (the licensee) dated June 17, 2008, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. NPF-37 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No. 158, and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented prior to the return to service from the Byron, Unit No. 2, fall 2008 Refueling Outage 14.

FOR THE NUCLEAR REGULATORY COMMISSION

Russell Gibbs, Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications and Facility Operating License

Date of Issuance: October 1, 2008

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

EXELON GENERATION COMPANY, LLC

DOCKET NO. STN 50-455

BYRON STATION, UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 158
License No. NPF-66

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Exelon Generation Company, LLC (the licensee) dated June 17, 2008, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. NPF-66 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendix A (NUREG 1113), as revised through Amendment No.158, and the Environmental Protection Plan contained in Appendix B, both of which are attached to License No. NPF-37, dated February 14, 1985, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented prior to the return to service from the Byron, Unit No. 2, fall 2008 Refueling Outage 14.

FOR THE NUCLEAR REGULATORY COMMISSION

Russell Gibbs, Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications and Facility Operating License

Date of Issuance: October 1, 2008

ATTACHMENT TO LICENSE AMENDMENT NOS.158 AND 158

FACILITY OPERATING LICENSE NOS. NPF-37 AND NPF-66

DOCKET NOS. STN 50-454 AND STN 50-455

Replace the following pages of the Facility Operating Licenses and the Appendix A Technical Specifications (TSs) with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
License NPF-37	License NPF-37
License Page 3	License Page 3
License NPF-66	License NPF-66
License Page 3	License Page 3
TSs	TSs
5.5-8	5.5-8
5.5-9	5.5-9
5.5-10	5.5-10
5.5-11	5.5-11
5.5-12	5.5-12
5.5-13	5.5-13
5.5-14	5.5-14
5.5-15	5.5-15
5.5-16	5.5-16
5.6-17	5.6-17
5.5-18	5.5-18
5.5-19	5.5-19
5.5-20	5.5-20
5.5-21	5.5-21
5.5-22	5.5-22
----	5.5-23
5.6-6	5.6-6
5.6-7	5.6-7

(4) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. The license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3586.6 megawatts thermal (100 percent power) in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No.158, and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Deleted.

(4) Deleted.

(5) Deleted.

(6) The licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the licensee's Fire Protection Report, and as approved in the SER dated February 1987 through Supplement No. 8, subject to the following provision:

The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

(3) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts are required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. The license shall be deemed to contain and is subject to the conditions specified in the Commission's regulation set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3586.6 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A (NUREG 1113), as revised through Amendment No158, and the Environmental Protection Plan contained in Appendix B, both of which are attached to License No. NPF-37, dated February 14, 1985, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Deleted.

(4) Deleted.

(5) Deleted.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed a total of 1 gpm for all SGs.

3. The operational LEAKAGE performance criteria is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube repair criteria.

1. Tubes found by inservice inspection to contain flaws in a non-sleeved region with a depth equal to or exceeding 40% of the nominal wall thickness shall be plugged or repaired except if permitted to remain in service through application of the alternate repair criteria discussed in TS 5.5.9.c.4. For Unit 2 only, during Refueling Outage 14 and the subsequent operating cycle, flaws identified in the portion of the tube from the top of the tubesheet to 17 inches below the top of the tubesheet shall be plugged or repaired upon detection.

2. Sleeves found by inservice inspection to contain flaws with a depth equal to or exceeding the following percentages of the nominal sleeve wall thickness shall be plugged:

i. For Unit 2 only, TIG welded sleeves (per TS 5.5.9.f.2.i): 32%

3. Tubes with a flaw in a sleeve to tube joint that occurs in the sleeve or in the original tube wall of the joint shall be plugged.

4. The following tube repair criteria shall be applied as an alternate to the 40% depth-based criteria of Technical Specification 5.5.9.c.1:

i. For Unit 2 only, during Refueling Outage 14 and the subsequent operating cycle, tubes with flaws having a circumferential component less than or equal to 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

the tubesheet do not require plugging or repair. Tubes with flaws having a circumferential component greater than 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service. Tubes with axial indications found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging or repair.

When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet or within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the Unit 1 tubes at sequential periods of 144, 108, 72, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

   Inspect 100% of the Unit 2 tubes at sequential periods of 120, 90, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 48 effective full power months or two refueling outages (whichever is less) without being inspected.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

f. Provisions for SG tube repair methods. Steam generator tube repair methods shall provide the means to reestablish the RCS pressure boundary integrity of SG tubes without removing the tube from service. For the purposes of these Specifications, tube plugging is not a repair.

1. There are no approved tube repair methods for the Unit 1 SGs.

2. All acceptable repair methods for the Unit 2 SGs are listed below.

i. TIG welded sleeving as described in ABB Combustion Engineering Inc., Technical Reports: Licensing Report CEN-621-P, Revision 00, "Commonwealth Edison Byron and Braidwood Unit 1 and 2 Steam Generators Tube Repair Using Leak Tight Sleeves, FINAL REPORT," April 1995; and Licensing Report CEN-627-P, "Operating Performance of the ABB CENO Steam Generator Tube Sleeve for Use at Commonwealth Edison Byron and Braidwood Units 1 and 2," January 1996; subject to the limitations and restrictions as noted by the NRC Staff.

5.5 Programs and Manuals

5.5.10 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser inleakage;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in conformance with Regulatory Guide 1.52, Revision 2, and ANSI N510-1980, with any exceptions noted in Appendix A of the UFSAR.

a. Demonstrate for each of the ESF filter systems that an inplace test of the High Efficiency Particulate Air (HEPA) filters shows a penetration specified below when tested in conformance with Regulatory Guide 1.52, Revision 2, and ANSI N510-1980, with any exceptions noted in Appendix A of the UFSAR, at the system flow rate specified below. Verification of the specified flow rates may be accomplished during the performance of SRs 3.7.10.4, 3.7.12.4, and 3.7.13.5, as applicable:

ESF Ventilation System	Flow Rate	Penetration
Control Room Ventilation (VC) Filtration System (makeup)	≥ 5400 cfm and ≤ 6600 cfm	< 0.05%
Nonaccessible Area Exhaust Filter Plenum Ventilation System (after structural maintenance of the HEPA filter housings)	≥ 55,669 cfm and ≤ 68,200 cfm per train, and ≥ 18,556 cfm and ≤ 22,733 cfm per bank	< 1%
Nonaccessible Area Exhaust Filter Plenum Ventilation System (for reasons other than structural maintenance of the HEPA filter housings)	≥ 55,669 cfm and ≤ 68,200 cfm per train	< 1%
Fuel Handling Building Exhaust Filter Plenum (FHB) Ventilation System	≥ 18,900 cfm and ≤ 23,100 cfm	< 1%

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

b. Demonstrate for each of the ESF filter systems that an inplace test of the charcoal adsorber shows a bypass specified below when tested in conformance with Regulatory Guide 1.52, Revision 2, and ANSI N510-1980, with any exceptions noted in Appendix A of the UFSAR, at the system flow rate specified below. Verification of the specified flow rates may be accomplished during the performance of SRs 3.7.10.4, 3.7.12.4, and 3.7.13.5, as applicable:

ESF Ventilation System	Flow Rate	Bypass
VC Filtration System (makeup)	≥ 5400 cfm and ≤ 6600 cfm	< 1%
VC Filtration System (recirculation, charcoal bed after complete or partial replacement)	≥ 44,550 cfm and ≤ 54,450 cfm	< 0.1%
VC Filtration System (recirculation for reasons other than complete or partial charcoal bed replacement)	≥ 44,550 cfm and ≤ 54,450 cfm	< 2%
Nonaccessible Area Exhaust Filter Plenum Ventilation System (after structural maintenance of the charcoal adsorber housings)	≥ 55,669 cfm and ≤ 68,200 cfm per train, and ≥ 18,556 cfm and ≤ 22,733 cfm per bank	< 1%
Nonaccessible Area Exhaust Filter Plenum Ventilation System (for reasons other than structural maintenance of the charcoal adsorber housings)	≥ 55,669 cfm and ≤ 68,200 cfm per train	< 1%
FHB Ventilation System	≥ 18,900 cfm and ≤ 23,100 cfm per train	< 1%

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

c. Demonstrate for each of the ESF filter systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 2, shows the methyl iodide penetration less than the value specified below when tested in conformance with Regulatory Guide 1.52, Revision 2, ANSI N510-1980, and ASTM D3803-1989, with any exceptions noted in Appendix A of the UFSAR, at a temperature of 30°C and a Relative Humidity (RH) specified below:

ESF Ventilation System	Penetration	RH
VC Filtration System (makeup)	2.0%	70%
VC Filtration System (recirculation)	4%	70%
Nonaccessible Area Exhaust Filter Plenum Ventilation System	4.5%	70%
FHB Ventilation System	10%	95%

d. Demonstrate for each of the ESF filter systems that the pressure drop across the combined HEPA filters and the charcoal adsorbers is < 6 inches of water gauge when tested in conformance with Regulatory Guide 1.52, Revision 2, and ANSI N510-1980, with any exceptions noted in Appendix A of the UFSAR, at the system flow rate specified below. Verification of the specified flow rates may be accomplished during the performance of SRs 3.7.10.4, 3.7.12.4, and 3.7.13.5, as applicable:

ESF Ventilation System	Flow Rate
VC Filtration System (makeup)	≥ 5400 cfm and ≤ 6600 cfm
Nonaccessible Area Exhaust Filter Plenum Ventilation System	≥ 55,669 cfm and ≤ 68,200 cfm per train
FHB Ventilation System	≥ 18,900 cfm and ≤ 23,100 cfm

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

e. Demonstrate for each of the ESF filter systems that a bypass test of the combined HEPA filters and damper leakage shows a total bypass specified below at the system flow rate specified below. Verification of the specified flow rates may be accomplished during the performance of SRs 3.7.12.4 and 3.7.13.5, as applicable:

ESF Ventilation System	Flow Rate	Bypass
Nonaccessible Area Exhaust Filter Plenum Ventilation System	≥ 55,669 cfm and ≤ 68,200 cfm per train	≤ 1%
FHB Ventilation System	≥ 18,900 cfm and ≤ 23,100 cfm	≤ 1%

f. Demonstrate that the heaters for each of the ESF filter systems dissipate the value specified below when tested in conformance with ANSI N510-1980, with any exceptions noted in Appendix A of the UFSAR.

ESF Ventilation System	Wattage
VC Filtration System	≥ 24.0 kW

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5 Programs and Manuals

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the waste gas system, the quantity of radioactivity contained in gas decay tanks or fed into the off gas treatment system, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. The gaseous radioactivity quantities shall be determined following the methodology in Branch Technical Position (BTP) ETSB 11-5, "Postulated Radioactive Release due to Waste Gas System Leak or Failure." The liquid radwaste quantities shall be determined in accordance with the ODCM.

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the waste gas system and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

b. A surveillance program to ensure that the quantity of radioactivity contained in each gas decay tank and fed into the offgas treatment system is less than the amount that would result in a whole body exposure of ≥ 0.5 rem to any individual in an unrestricted area, in the event of an uncontrolled release of the tanks' contents; and

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system is less than the amount that would result in concentrations less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5 Programs and Manuals

5.5.13 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

    1. an API gravity or an absolute specific gravity within limits,

    2. a flash point and kinematic viscosity within limits, and

    3. a clear and bright appearance with proper color or a water and sediment content within limits;

b. Other properties of new fuel oil are within limits within 30 days following sampling and addition to storage tanks; and

c. Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 31 days.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program test frequencies.

5.5 Programs and Manuals

5.5.14 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

   1. a change in the TS incorporated in the license; or

   2. a change to the UFSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

d. Proposed changes that meet the criteria of Specification 5.5.14.b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e) as modified by approved exemptions.

5.5 Programs and Manuals

5.5.15 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

5.5 Programs and Manuals

5.5.15 Safety Function Determination Program (SFDP) (continued)

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.16 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, September 1995 and NEI 94-01, Revision 0, as modified by the following exceptions:

1. NEI 94-01 - 1995, Section 9.2.3: The first Unit 1 Type A test performed after the February 19, 1998 Type A test shall be performed no later than February 19, 2013.

2. NEI 94-01 - 1995, Section 9.2.3: The first Unit 2 Type A test performed after the November 2, 1999 Type A test shall be performed no later than November 2, 2014.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 42.8 psig for Unit 1 and 38.4 psig for Unit 2

The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.20% of containment air weight per day.

Leakage Rate acceptance criteria are:

a. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for the Type B and C tests and $< 0.75\ L_a$ for Type A tests; and

5.5 Programs and Manuals

5.5.16 Containment Leakage Rate Testing Program (continued)

b. Air lock testing acceptance criteria are:

1. Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$; and

2. For each door, seal leakage rate is:

i. $< 0.0024\ L_a$, when pressurized to ≥ 3 psig, and

ii. $< 0.01\ L_a$, when pressurized to ≥ 10 psig.

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program.

The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

5.5.17 Battery Monitoring and Maintenance Program

This program provides for restoration and maintenance, based on the recommendations of IEEE Standard 450, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead - Acid Batteries For Stationary Applications," or of the battery manufacturer of the following:

A. Actions to restore battery cells with float voltage < 2.13 V, and

B. Actions to equalize and test battery cells that had been discovered with electrolyte level below the minimum established design limit.

5.5.18 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Ventilation (VC) Filtration System, CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident. The program shall include the following elements:

5.5 Programs and Manuals

5.5.18 Control Room Envelope Habitability Program (continued)

a. The definition of the CRE and the CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

d. Measurement, at designed locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the VC Filtration System, operating at the flow rate required by the VFTP, at a Frequency of 18 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the 18 month assessment of the CRE boundary.

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

5.6 Reporting Requirements

5.6.8 Tendon Surveillance Report

Any abnormal degradation of the containment structure detected during the tests required by the Pre-Stressed Concrete Containment Tendon Surveillance Program shall be reported in the Inservice Inspection Summary Report in accordance with 10 CFR 50.55a and ASME Section XI, 1992 Edition with the 1992 Addenda.

5.6.9 Steam Generator (SG) Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged or repaired during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged or repaired to date,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing,

h. The effective plugging percentage for all plugging and tube repairs in each SG, and

i. Repair method utilized and the number of tubes repaired by each repair method.

j. For Unit 2, following completion of an inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, and whether initiated on primary or secondary side for each service-induced flaw detected within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet, as determined in accordance with TS 5.5.9 c.4.i,

5.6 Reporting Requirements

5.6.9 Steam Generator (SG) Tube Inspection Report (continued)

k. For Unit 2, following completion of an inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, the entire primary to secondary leakage should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report, and

l. For Unit 2, following completion of an inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the lowermost 4-inches of tubing for the most limiting accident in the most limiting steam generator.

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 158 TO FACILITY OPERATING LICENSE NO. NPF-37

AND AMENDMENT NO. 158 TO FACILITY OPERATING LICENSE NO. NPF-66

EXELON GENERATION COMPANY, LLC

BYRON STATION, UNIT NOS. 1 AND 2

DOCKET NOS. STN 50-454 AND STN 50-455

1.0 INTRODUCTION

By letter to the Nuclear Regulatory Commission (NRC, the Commission) dated June 17, 2008 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML081780134), Exelon Generation Company, LLC (EGC, the licensee) submitted a license amendment request to change the technical specifications (TSs) for Byron Station (Byron), Unit No. 2. The request proposed changes to the repair requirements of TS 5.5.9, "Steam Generator (SG) Program," and to the reporting requirements of TS 5.6.9, "Steam Generator (SG) Tube Inspection Report." The proposed changes would establish an interim alternate repair criteria (IARC) for portions of the SG tubes within the tubesheet, and would be applicable to Unit No. 2 during Refueling Outage 14 (2R14), planned for the fall of 2008, and the subsequent operating cycle.

The Commission published a no significant hazards consideration determination in an individual notice in the *Federal Register* on August 5, 2008 (73 FR 45485).

In its letter dated June 17, 2008, the licensee submitted Westinghouse Electric Company (Westinghouse) documents, LTR-CDME-08-11, Revision 3 P-Attachment, "Interim Alternate Repair Criterion (IARC) for Cracks in the Lower Region of the Tubesheet Expansion Zone," dated June 3, 2008, and LTR-CDME-08-43, Revision 3 P-Attachment, "Response to NRC Request for Additional Information (RAI) Relating to LTR-CDME-08-11, Rev. 3 P-Attachment," dated June 3, 2008. The documents contained proprietary information and the affidavits, executed by Westinghouse requesting that the NRC staff withhold the proprietary information from the public, were also submitted in the letter. The NRC staff letter approving the withholding of the information from the public, in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR), paragraph 2.390(b)(5) and Section 103(b) of the Atomic Energy Act of 1954, as amended, was issued on August 4, 2008 (ADAMS Accession No. ML081980108). There is no proprietary information in this safety evaluation.

2.0 BACKGROUND

Byron, Unit No. 2, has four Westinghouse Model D5 SGs. There are 4570 thermally-treated Alloy 600 tubes in each SG, each with an outside diameter of 0.750 inches and a nominal wall thickness of 0.043 inches. The tubes are hydraulically-expanded for the full depth of the

tubesheet (21.2 inches) at each end and are welded to the tubesheet at the bottom of each expansion.

Until the fall of 2004, no instances of stress corrosion cracking (SCC) affecting the tubesheet region of thermally-treated alloy 600 tubing had been reported, at Byron or other nuclear power plants in the United States. As a result, most plants, including Byron, had been using bobbin probes for inspecting the length of tubing within the tubesheet. Since bobbin probes are not capable of reliably detecting SCC in the tubesheet region, supplementary rotating coil probe inspections were used in a region extending from 3 inches above the top of the tubesheet (TTS) to 3 inches below the TTS. This zone includes the tube-expansion transition, which contains significant residual stress, and was considered a likely location for SCC to develop.

In the fall of 2004, crack-like indications were found in tubes in the tubesheet region of Catawba Nuclear Station, Unit 2 (Catawba), which also has Westinghouse Model D5 SGs. Like Byron, the Catawba SGs employ thermally-treated alloy 600 tubing that is hydraulically-expanded against the tubesheet. At the time of cracking, Catawba had accumulated 14.7 effective full power years of service, which is similar to the service experience that the SGs at Byron have accumulated, with a comparable hot-leg operating temperature. The crack-like indications at Catawba were found in overexpansions (OPXs) in the tubesheet region, in the tack expansion region, and near the tube-to-tubesheet weld. (It is also noted that Vogtle Unit 1 found crack-like indications in bulges.) The tack expansion is an approximately 1 inch long expansion at each tube end. The purpose of the tack expansion is to facilitate performing the tube-to-tubesheet weld, which is made prior to the hydraulic expansion of the tube over the full tubesheet depth.

As a result of the Catawba findings, the Byron licensee expanded the scope of rotating coil inspections to include OXPs during 2R12 (fall 2005) and reported that they found no degradation. During 2R13 (spring 2007), Byron again performed rotating coil inspections of OXPs within the tubesheet. The inspections focused on the upper 17 inches of the tube within the tubesheet, since the licensee concluded that flaws located below 17 inches from the TTS (i.e., in the bottom 4 inches of the tube within the tubesheet) had no potential to impair tube integrity. The NRC staff approved restricting the inspection and repair of flawed tubes to the upper 17 inches of the tube within the hot-leg tubesheet, in Amendment No. 150 for Byron, Unit No. 2, on March 30, 2007. Amendment No. 150 applied to 2R13 and the subsequent operating cycle.

By letter dated November 29, 2007 (ADAMS Accession No. ML073380100), Southern Nuclear Operating Company submitted a license amendment request for Vogtle Electric Generating Plant (VEGP), Units 1 and 2, which would make the inspection and repair modifications approved in previous VEGP amendments (which were similar to Amendment No. 150 for Byron, Unit No. 2) permanent, and would add some additional reporting requirements under TS section 5.6.9, "Steam Generator Tube Inspection Report." The permanent amendment request was based on a technical analysis approach, identified as H*/B*, that was also used as a basis for a permanent amendment request submitted by Wolf Creek Nuclear Operating Corporation (WCNOC) for the Wolf Creek Generating Station on February 21, 2006. After three requests for additional information (RAIs) and several meetings with WCNOC, the NRC staff informed WCNOC during a phone call on January 3, 2008, that it had not provided sufficient information to allow the NRC staff to review and approve the permanent license amendment request.

Because the lack of information in the technical analysis mentioned above prevented the NRC staff from approving a permanent amendment to the TS inspection and reporting criteria, both WCNOC and VEGP submitted revised applications with a more conservative IARC approach. After WCNOC and VEGP responded to new NRC RAIs regarding the IARC, the NRC staff

approved the IARC amendments in letters dated April 4, 2008 (ADAMS Accession No. ML080840004), and April 9, 2008 (ADAMS Accession No. ML080950247), respectively.

As stated previously, by letter dated June 17, 2008, the licensee submitted a license amendment request to change the TSs for Byron, Unit No. 2. The request proposed changes to the repair requirements of TS 5.5.9, "Steam Generator (SG) Program," and to the reporting requirements of TS 5.6.9, "Steam Generator (SG) Tube Inspection Report." The proposed changes would establish an IARC for portions of the SG tubes within the tubesheet, and would be applicable during 2R14 and the subsequent operating cycle.

3.0 REGULATORY EVALUATION

In 10 CFR 50.36, the Commission established its regulatory requirements related to the content of the TSs. Pursuant to 10 CFR 50.36, TSs are required to include items in the following five specific categories related to station operation: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation (LCOs); (3) surveillance requirements; (4) design features; and (5) administrative controls. The TSs for the licensee's June 17, 2008, license amendment request are in category (5). The rule does not specify the particular requirements to be included in a plant's TSs. In 10 CFR 50.36(d)(5), administrative controls are stated to be "the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure the operation of the facility in a safe manner." This also includes the programs established by the licensee and listed in the administrative controls section of the TSs for the licensee to operate the facility in a safe manner. The requirements for (1) SG tube inspections and repair, and (2) reporting on these inspections and repair for Byron are in TS 3.4.19, "Steam Generator (SG) Tube Integrity," and TS 5.5.9, and in TS 5.6.9, respectively.

The TSs for all pressurized-water reactor (PWR) plants require that an SG program be established and implemented to ensure that SG tube integrity is maintained. For Byron, SG tube integrity is maintained by meeting specified performance criteria (in TS 5.5.9.b) for structural and leakage integrity, consistent with the plant design and licensing basis. TS 5.5.9.a requires that a condition monitoring assessment be performed during each outage in which the SG tubes are inspected, to confirm that the performance criteria are being met. TS 5.5.9 also includes provisions regarding the scope, frequency, and methods of SG tube inspections. Of relevance to the subject amendment request, these provisions require that the inspections be performed with the objective of detecting flaws of any type that may be present along the length of a tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria (except as indicated above regarding the one-cycle application of a limited scope of inspection in the tubesheet region). The applicable tube repair criteria, specified in TS 5.5.9.c.1, are that tubes found by inservice inspection to contain flaws in a non-sleeved region with a depth equal to or exceeding 40 percent of the nominal wall thickness shall be plugged or repaired except if permitted to remain in service through application of the alternate repair criteria discussed in TS 5.5.9.c.4.

The SG tubes function as an integral part of the reactor coolant pressure boundary (RCPB) and, in addition, serve to isolate radiological fission products in the primary reactor coolant from the secondary coolant and the environment. For the purposes of this SE, SG tube integrity means that the tubes are capable of performing these safety functions in accordance with the plant design and licensing basis.

The General Design Criteria (GDC) in Appendix A to 10 CFR Part 50 state that the RCPB shall have “an extremely low probability of abnormal leakage . . . and gross rupture" (GDC 14), "shall be designed with sufficient margin" (GDCs 15 and 31), shall be of "the highest quality standards practical" (GDC 30), and shall be designed to permit "periodic inspection and testing . . . to assess . . . structural and leaktight integrity" (GDC 32). To this end, 10 CFR 50.55a specifies that components that are part of the RCPB must meet the requirements for Class 1 components in Section III of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code). Section 50.55a further requires, in part, that throughout the service life of a PWR facility like Byron, ASME Code Class 1 components meet the requirements, except design and access provisions and pre-service examination requirements, in Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," of the ASME Code, to the extent practical. This requirement includes the inspection and repair criteria of Section XI of the ASME Code. Section XI requirements pertaining to inservice inspection of SG tubing are augmented by additional requirements in the TSs.

As part of the plant licensing basis, applicants for PWR licenses are required to analyze the consequences of postulated design-basis accidents (DBAs) such as a SG tube rupture and main steam line break (MSLB). These analyses consider primary-to-secondary leakage, which may occur during these events, and must show that the offsite radiological consequences do not exceed the applicable limits of the 10 CFR 50.67, Accident source term, GDC 19 criteria for control room operator doses, or some fraction thereof as appropriate to the accident, or the NRC-approved licensing basis (e.g., a small fraction of these limits). No accident analysis for Byron is being changed because of the proposed amendments and, thus, no radiological consequences of any accident analysis are being changed.

The licensee-proposed changes to TS 5.5.9 stay within the GDC requirements for the SG tubes and maintain the accident analysis and consequences that the NRC staff has reviewed and approved for the postulated DBAs for SG tubes. License Amendment No. 150 modified the TS wording at Byron, Unit No. 2, to restrict the required inspection and plugging in the hot-leg tubesheet region to the uppermost 17 inches of the tubesheet region for 2R13 and the subsequent operating cycle. This excluded the lowermost 4 inches of the tube in the hot-leg tubesheet from the TS inspection and plugging requirements. Amendment No. 150 also added a requirement that all tubes found with flaws in the upper 17 inches of the hot-leg tubesheet region be plugged, to provide added assurance that tube-to-tubesheet joint integrity would be maintained.

The proposed amendments are applicable to Byron, Unit No. 2, for 2R14 and the subsequent operating cycle. They differ from Amendment No. 150 in a number of ways. First, the lowermost 4 inches of the tube in the tubesheet would no longer be excluded from the TS inspection requirements in TS 5.5.9.d. The lowermost 4 inches of tubing would be subject to the same inspection requirements as the rest of the tubing. Second, any flaws in the lowermost 4 inches of the tube in the tubesheet would not be excluded from requirements to plug. Under the proposed amendments, flaws found in the lowermost 4 inches of tubing would be subject to the IARC in lieu of the aforementioned 40 percent depth-based criterion; the latter criterion would continue to be applicable outside of the tubesheet region. Third, the proposed amendments applie to both the hot- and cold-leg sides of the tubesheet. Fourth, the proposed amendments would include new reporting requirements to allow the NRC staff to monitor the implementation of the amendments. As with Amendment No. 150 for the hot-leg side, the proposed amendments would require the plugging of all tubes found with flaws in the upper 17 inches of the tubesheet region on both the hot- and cold-leg sides.

4.0 TECHNICAL EVALUATION

4.1 Proposed Changes to the TSs

TS 5.5.9.c currently states:

c. Provisions for SG tube repair criteria.

1. Tubes found by inservice inspection to contain flaws in a non-sleeved region with a depth equal to or exceeding 40% of the nominal wall thickness shall be plugged or repaired except if permitted to remain in service through application of the alternate repair criteria discussed in TS 5.5.9.c.4. For Unit 2 only, during Refueling Outage 13 and the subsequent operating cycle, flaws identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet shall be plugged or repaired upon detection.

2. Sleeves found by inservice inspection to contain flaws with a depth equal to or exceeding the following percentages of the nominal sleeve wall thickness shall be plugged:

   i. TIG welded sleeves (per TS 5.5.9.f.2.i): 32%

3. Tubes with a flaw in a sleeve to tube joint that occurs in the sleeve or in the original tube wall of the joint shall be plugged.

4. The following tube repair criteria may be applied as an alternate to the 40% depth-based criteria of Technical Specification 5.5.9.c.1:

   i. For Unit 2 only, during Refueling Outage 13 and the subsequent operating cycle, flaws found in the portion of the tube below 17 inches from the top of the hot leg tubesheet do not require plugging or repair.

The criteria would be revised as follows, as noted in strikeout and italic type:

c. Provisions for SG tube repair criteria.

1. Tubes found by inservice inspection to contain flaws in a non-sleeved region with a depth equal to or exceeding 40% of the nominal wall thickness shall be plugged or repaired except if permitted to remain in service through application of the alternate repair criteria discussed in TS 5.5.9.c.4. For Unit 2 only, during Refueling Outage ~~13~~ *14* and the subsequent operating cycle, flaws identified in the portion of the tube from the top of the ~~hot leg~~ tubesheet to 17 inches below the top of the tubesheet shall be plugged or repaired upon detection.

2. Sleeves found by inservice inspection to contain flaws with a depth equal to or exceeding the following percentages of the nominal sleeve wall thickness shall be plugged:

   i. *For Unit 2 only,* TIG welded sleeves (per TS 5.5.9.f.2.i): 32%

3. Tubes with a flaw in a sleeve to tube joint that occurs in the sleeve or in the original tube wall of the joint shall be plugged.

4. The following tube repair criteria ~~may~~ *shall* be applied as an alternate to the 40% depth-based criteria of Technical Specification 5.5.9.c.1:

   i. For Unit 2 only, during Refueling Outage ~~13~~ *14* and the subsequent operating cycle, ~~flaws found in the portion of the tube below 17 inches from the top of the hot leg tubesheet do not require plugging or repair.~~ *tubes with flaws having a circumferential component less than or equal to 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet do not require plugging or repair. Tubes with flaws having a circumferential component greater than 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service. Tubes with axial indications found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging or repair.*

      When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

      When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet or within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

TS 5.5.9.d currently states, in part:

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. For Unit 2 only, during Refueling Outage 13 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded. The tube-to-tubesheet weld is not part of the tube.

This criterion would be revised as follows, as noted in strikeout type:

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g.,

volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. ~~For Unit 2 only, during Refueling Outage 13 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded.~~ The tube-to-tubesheet weld is not part of the tube.

TS 5.6.9 currently states:

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged or repaired during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged or repaired to date,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing,

h. The effective plugging percentage for all plugging and tube repairs in each SG, and

i. Repair method utilized and the number of tubes repaired by each repair method.

j. For Unit 2, following completion of an inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, and whether initiated on primary or secondary side for each indication detected in the upper 17-inches of the tubesheet thickness.

k. For Unit 2, following completion of an inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent operating cycle), the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, the entire primary to secondary leakage should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report.

l. For Unit 2, following completion of an inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the lowermost 4-inches of tubing for the

most limiting accident in the most limiting steam generator. In addition, if the calculated accident leakage rate from the most limiting accident is less than 2 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined.

TS 5.6.9 would be revised as follows, as noted in strikeout and italic type:

j. For Unit 2, following completion of an inspection performed in Refueling Outage ~~13~~ *14* (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, and whether initiated on primary or secondary side for each ~~indication~~ *service-induced flaw* detected *with*in ~~the upper 17-inches of~~ *the thickness of the* tubesheet, *and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet, as determined in accordance with TS 5.5.9.c.4.1,* ~~thickness.~~

k. For Unit 2, following completion of an inspection performed in Refueling Outage ~~13~~ *14* (and any inspections performed in the subsequent operating cycle), the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, the entire primary to secondary leakage should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report~~.~~, and

l. For Unit 2, following completion of an inspection performed in Refueling Outage ~~13~~ *14* (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the lowermost 4-inches of tubing for the most limiting accident in the most limiting steam generator. ~~In addition, if the calculated accident leakage rate from the most limiting accident is less than 2 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined.~~

4.2 Technical Evaluation

The tube-to-tubesheet joint consists of the tube, which is hydraulically-expanded against the bore of the tubesheet; the tube-to-tubesheet weld located at the tube end; and the tubesheet. The joint was designed as a welded joint and not as a friction or expansion joint. The weld itself was designed as a pressure boundary element. It was designed to transmit the entire end-cap pressure load during normal and DBA conditions from the tube to the tubesheet with no credit taken for the friction developed between the hydraulically-expanded tube and the tubesheet. In addition, the weld serves to make the joint leak-tight.

The one-cycle amendments approved for Byron, Unit No. 2 (Amendment No. 150) and other plants (such as Vogtle) prior to 2008, exempted the lower 4-inch portion of the tube within the 21-inch-deep tubesheet from inspection and exempted tubes with flaw indications in this region from being removed from service (i.e., plugged). These one-cycle amendments, in effect, redefined the pressure boundary at the tube-to-tubesheet joint as consisting of a friction or expansion joint with the tube hydraulically-expanded against the tubesheet over the top 17 inches of the tubesheet. These amendments took no credit for the lower portion of the tube or the tube-to-tubesheet weld as contributing to the structural or leakage integrity of the joint.

The proposed amendments that are the subject of this safety evaluation (and similar amendments approved in 2008 for Wolf Creek, Vogtle, Braidwood, and Surry) differs fundamentally from the one-cycle amendments approved prior to 2008 and is a more conservative approach. The proposed amendments treat the tube-to-tubesheet joint as a welded joint in a manner consistent with the original design basis, with no credit taken for the friction developed between the hydraulically-expanded tube and the tubesheet. The proposed amendments are intended to ensure that the aforementioned end-cap loads can be transmitted down the tube, through the tube-to-tubesheet weld, and into the tubesheet.

4.2.1 Proposed Change to TS 5.5.9.c, "Provisions for SG tube repair criteria"

The 40 percent depth-based tube repair criterion in TS 5.5.9.c is intended to ensure, in conjunction with other elements of TS 5.5.9, that tubes accepted for continued service (i.e., not plugged) satisfy the performance criteria for structural integrity in TS 5.5.9.b.1 and the performance criteria for accident leakage integrity in TS 5.5.9.b.2. The criterion includes an allowance for eddy current measurement error and incremental flaw growth prior to the next inspection of the tube. The alternate tube repair criteria in the existing TSs and the proposed IARC in these amendments are alternatives to this 40 percent depth-based criterion.

4.2.1.1 Structural Integrity Considerations

The 40 percent depth-based criterion was developed to be conservative for flaws located anywhere in the SG, including free span regions, In the tubesheet, however, the tubes are constrained against radial expansion by the tubesheet and, therefore, are constrained against an axial (fish-mouth) rupture failure mode. The only potential structural failure mode within the tubesheet is a circumferential failure mode, leading to tube severance.

The proposed IARC would permit tubes with up to 100 percent through-wall flaws in the portion of the tube from 17 inches below the TTS to 1 inch above the bottom of the tubesheet to remain in service provided the circumferential component of these flaws does not exceed 203 degrees. The 203-degree criterion was determined on the basis of the remaining cross-sectional area of the tube needed to resist the limiting axial end-cap load on the tube and the pressure load on the flaw cross-section, using limit-load analysis, with safety factors consistent with those required by the performance criteria for structural integrity in TS. Because the 203-degree criterion was determined on this basis, the NRC staff finds this approach acceptable.

For the portion of the tube from the bottom of the tubesheet to 1 inch above the bottom of the tubesheet, the proposed IARC would permit tubes with up to 100 percent through-wall flaws to remain in service provided the circumferential component of these flaws does not exceed 94 degrees. This criterion is based on the minimum tube-to-tubesheet weld cross-sectional area needed to resist the limiting axial end-cap load on the tube and the pressure load on the flaw cross-section, using limit load analysis, with safety factors consistent with those required by the performance criteria for structural integrity in the TS. A 203-degree crack in the tube wall immediately above the weld could potentially concentrate the entire end cap load to a 157-degree segment of the weld, whereas a minimum 266 degree segment (i.e., 360 minus 94 degrees) of weld is needed to resist the end-cap load with adequate safety margin. Thus, the 94-degree criterion for the tube in the lowermost 1-inch region is intended to ensure that the weld is not overstressed. Although the NRC staff did not complete its review of the specific limit-load methodology used to calculate the 94-degree criterion, it reviewed the results of the stress analysis of the weld, which was performed to demonstrate that the weld complied with the stress limits of the ASME Code, Section III. The TS performance criteria for tube structural integrity are intended to ensure safety margins consistent with the ASME Code, Section III stress

limits. Based on a comparison of the calculated maximum design stress to the ASME Code-allowable stress, the NRC staff concludes that the proposed 94-degree criterion ensures that the weld can carry the end-cap loads with margins to failure consistent with the margins ensured by the ASME stress limits and is, therefore, acceptable.

The 203- and 94-degree criteria include an allowance for incremental flaw growth in the circumferential direction prior to the next inspection. The licensee stated that no significant growth rate data exists for the specific case of circumferential cracking in the tubesheet expansion region. The licensee's growth rate estimate is based on a 95 percent upper bound value of available primary water stress corrosion crack (PWSCC) growth rate data for other tube locations. Given the lack of actual growth rate data for cracks that may potentially initiate in the lowermost 4 inches of the tube, the NRC staff attaches only a low level of confidence in the conservatism of the licensee's growth rate estimate. However, the NRC staff notes that the effect of any lack of conservatism in the licensee's estimate is mitigated somewhat by the fact that if crack indications are found in any SG tube, then the next inspection for each SG, for the degradation mechanism that caused the crack indication, shall not exceed 24 effective full power months or one refueling outage (whichever is less). In addition, the 203- and 94-degree criteria conservatively take no credit for the effects of friction between the tube and tubesheet in any portion of the tube-to-tubesheet joint, in reacting out a portion of the axial end cap load before it reaches the cracked cross-section. Thus, the NRC staff concludes that the 203- and 94-degree criteria are conservative, irrespective of growth rate uncertainties.

The 203- and 94-degree criteria do not include an explicit allowance for eddy current measurement error. The licensee will be utilizing an inspection technique that has been qualified for the detection of circumferential PWSCC in tube expansion transitions, and in the tack expansion region just above the tube to tubesheet weld. The tack expansion is an approximately 1-inch long expansion of the tube in the tubesheet that is performed before the tube is hydraulically-expanded for the entire depth of the tubesheet. A fundamental assumption behind the proposed 203- and 94-degree repair criteria is that all detected circumferential flaws in the lowermost 4 inches of the tube are fully 100 percent through-wall, irrespective of the actual depth of the flaw. With this assumption, the licensee referenced an Electric Power Research Institute (EPRI) sponsored study that indicated the eddy current measurement of the crack arc length was conservative (i.e., larger than the actual crack size), and resulted in an estimate of the remaining cross sectional area that was always smaller than values obtained through direct measurement of cracks. Although the NRC staff has not reviewed the EPRI study in detail, it finds, based on the results of the study, that any uncertainties relating to measured arc length of the flaw are not expected to impair the conservatism of the 203- and 94-degree criteria.

The proposed IARC also includes criteria to account for interaction effects for multiple circumferential flaws that are in close proximity. The proposed criteria treat the multiple circumferential flaws located within 1 inch of one another as all occurring at the same axial location. The total arc length of the combined flaw is the sum of the individual flaw arc lengths with overlapping arc lengths counted only once. The licensee stated that the summation of cracks with both located more than 17 inches from the TTS and more than 1 inch from the bottom of the tube will be compared to the 203-degree criterion. The summation of cracks with one flaw located less than 1 inch from the bottom of the tubesheet and the other within 1 inch of the first (or both flaws within 1 inch of the bottom of the tubesheet) would be compared to the 94-degree criterion. Cracks located more than 1 inch apart are assumed to act independently of each other. This 1-inch criterion was determined using a fracture mechanics approach to determine the axial distance from an individual crack tip at which the stress distribution reverts to a nominal stress distribution for an uncracked section. The 1-inch criterion is twice the calculated distance since twice this distance is the necessary separation between two cracks for

the cracks to act independently of each other. The NRC staff reviewed the basis for the 1-inch criterion and the fracture mechanics approach to determining the criterion. Because the criterion is based on a valid fracture mechanics approach, the NRC staff finds it acceptable.

The proposed ARC would permit tubes with axial cracks in the lower-most 4 inches of the tube to remain in service, irrespective of crack depth. The NRC staff finds this acceptable because axial cracks do not impair the ability of the tube or the weld to resist axial load and because the tube is fully constrained by the tubesheet against an axial failure mode.

Finally, the proposed IARC includes a requirement to plug all tubes in which flaws are detected in the upper 17-inch portion of the tube within the tubesheet. This adds to the conservatism of the 203- and 94-degree criteria because it mitigates any loss of tightness and, thus, any loss of friction between the tube and tubesheet due to flaws in the upper 17-inch region of the joint.

4.2.1.2 Accident Leakage Integrity Considerations

If a tube is assumed to contain a 100 percent through wall flaw some distance into the tubesheet, a potential leak path between the primary and secondary systems is introduced between the hydraulically-expanded tubing and the tubesheet. Operational leakage integrity is assured by monitoring primary-to-secondary leakage relative to the applicable TS LCO limits in TS 3/4.4.6, "Reactor Coolant System Leakage." However, it must also be demonstrated that the proposed TS changes do not create the potential for leakage during DBAs to exceed the accident leakage performance criteria in TS 5.5.9.b.2, including the leakage values assumed in the plant licensing basis accident analyses. The licensee stated that this is ensured for Byron by limiting primary-to-secondary leakage to 0.50 gallon per minute in the faulted SG during an MSLB accident.

The leakage path between the tube and tubesheet has been modeled by the licensee's contractor, Westinghouse, as a crevice consisting of a porous media. Using Darcy's model for flow through a porous media, leak rate is proportional to differential pressure and inversely proportional to flow resistance. Flow resistance is a direct function of viscosity, loss coefficient, and crevice length. Westinghouse performed leak tests of tube-to-tubesheet joint mockups to establish loss coefficient as a function of contact pressure. Westinghouse states that the flow resistance varies as a log normal linear function of joint contact pressure, but due to the large scatter of the flow resistance test data, has been assumed to be constant with joint contact pressure at a value which conservatively lower bounds the data.

Using the above model, a "modified B*" approach for calculating accident leakage was initially proposed in the amendment request. The proposed modified B* approach relies to some extent on an assumed, constant value of loss coefficient, based on a lower bound of the data. This contrasts with the "nominal B*" approach which, in its latest form, is not directly impacted by the assumed value of loss coefficient since this value is assumed to be constant with increasing contact pressure between the tube and tubesheet. The NRC staff is not able to make a conclusion as to whether the assumed value of loss coefficient in the "modified B*" approach is conservative at this time. However, the NRC staff has performed some evaluations regarding the potential for the normal operating leak rate to increase under steam-line break conditions. Making the conservative assumption that loss coefficient and viscosity are constant under both normal operating and steam-line break conditions, the ratio of steam-line break leakage rate to normal operating leak rate is equal to the ratio of steam-line break differential pressure to normal operating differential pressure times the ratio of effective crevice length under normal operating conditions (l_{NOP}) to effective crevice length under steam-line break conditions (l_{SLB}). Effective crevice length is the crevice length over which there is contact between the tube and tubesheet.

Using various values of (I_{NOP}/ I_{SLB}) determined from the "nominal B*" approach (which does not rely on an assumed value of loss coefficient) and recognizing the issues associated with some of these previous H*/B* analyses, the NRC staff concludes that a factor of 2.5 reasonably bounds the potential increase in leakage from the lowermost 4 inches of tubing that would be realized in going from normal operating to steam-line break conditions.

The licensee provided a regulatory commitment in its June 17, 2008, letter stating that it would apply the 2.5 factor in its condition monitoring (CM) and operational assessment (OA) upon implementation of the subject license amendments. Specifically, for the CM assessment, the licensee states that the component of leakage from the lowermost 4 inches of tubing for the most limiting SG during the prior cycle of operation will be multiplied by a factor of 2.5 and added to the total leakage from any other source and compared to allowable accident leakage limit. For the OA, the licensee stated that the difference in leakage from the allowable accident leakage limit and the accident leakage from other sources will be divided by 2.5 and compared to the observed (operational) leakage and that an administrative limit (for operational leakage) will be established to not exceed the calculated value. Since this properly addresses the factor of 2.5 that bounds the potential increase in leakage in the lowermost 4 inches of tubing, the NRC staff finds this acceptable.

The NRC staff finds that reasonable controls for the licensee's implementation and subsequent evaluation of any changes to the regulatory commitment are provided by the licensee's administrative processes, including its commitment management program. The NRC staff has determined that the commitment does not warrant the creation of regulatory requirements, which would require prior NRC staff approval of subsequent changes. The NRC staff has agreed that Nuclear Energy Institute (NEI) 99-04, Revision 0, provides reasonable guidance for the control of regulatory commitments made to the NRC staff (Regulatory Issue Summary 2000-17, "Managing Regulatory Commitments Made by Power Reactor Licensees to the NRC Staff," dated September 21, 2000). These commitments will be controlled in accordance with the licensee's commitment management program in accordance with NEI 99-04. Any change to the regulatory commitments is subject to licensee management approval and subject to the procedural controls established at the plant for commitment management in accordance with NEI 99-04, which include notification of the NRC. Also, the NRC staff may choose to verify the implementation and maintenance of these commitments in a future inspection or audit.

4.2.2 Proposed Change to TS 5.5.9.d, "Provisions for SG tube inspections"

With the plant entry into 2R14, the sentence added to TS 5.5.9.d in Amendment No. 150 is no longer applicable and the licensee has proposed to delete the sentence. The sentence to be deleted states, "For Unit 2 only, during Refueling Outage 13 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded." Therefore, in 2R14, the inspection requirements of TS 5.5.9.d apply to the entire length of tubing from the tube-to-tubesheet weld location at the tube inlet to the tube-to-tubesheet weld location at the tube outlet. TS 5.5.9.d further states that the tube-to-tubesheet weld itself is not considered part of the tube. No changes relative to this wording are being proposed as part of the subject amendment request.

4.2.3 Proposed Change to TS 5.6.9, "Steam Generator (SG) Tube Inspection Report"

The NRC staff has reviewed the proposed new reporting requirements and finds that they are sufficient to allow the staff to monitor the implementation of the proposed amendments. Based on this conclusion, the NRC staff finds that the proposed new reporting requirements are acceptable.

4.2.4 Considerations Relating to Tube-to-Tubesheet Welds

The standard technical specifications and the Byron TSs state specifically that the tube to tubesheet welds are not part of the tube. Therefore, the requirements of TS 5.5.9 do not apply to these welds. However, licensees typically visually inspect the tube ends (including the welds) for evidence of leakage while the SG primary manways are open to permit eddy current inspection of the tubes.

Eddy-current inspection of the SG tubes at Catawba Unit 2 in 2007 revealed indications interpreted as cracks at or near the tube-to-tubesheet weld, suggesting the potential for such cracks in similar SGs, such as those at Byron. An industry peer review was recently conducted for the Catawba Unit 2 cold-leg tube-end indications to establish whether the reported indications are in the tube material or the welds. A consensus was reached that the indications most likely exist within the tube material. However, some of the indications extend close enough to the tube end that the possibility that the flaws extend into the weld could not be ruled out. An NRC staff member and an expert consultant from Argonne National Laboratory also reviewed these indications and concluded that the industry's position was reasonable. The peer review group and the NRC consultant also reviewed eddy-current signals from a tube-to-tubesheet mockup, which included a circumferential notch in one of the welds, and they concluded that this notch did not produce a detectable signal.

4.3 <u>Summary</u>

Based on the above evaluation, the NRC staff finds that the proposed license amendments, which are applicable to Byron, Unit No. 2, for 2R14 and the subsequent operating cycle, ensure that SG tube structural and leakage integrity will be maintained during this period with structural safety margins consistent with the design basis and with leakage integrity within assumptions employed in the licensing basis accident analyses, and will have no adverse impact on the ability of the tube-to-tubesheet welds to perform their safety-related function. Based on this finding, the NRC staff further concludes that the proposed amendments meet 10 CFR 50.36 and, thus, the proposed amendments are acceptable.

The current TSs and the proposed amendments do not address inspection requirements for the tube-to-tubesheet welds. There are no safety issues with respect to hypothetical cracks in the weld if it can be demonstrated, such as with the H*/B* strategies discussed in Section 2 of this safety evaluation, that the axial end-cap loads in the tube are reacted by frictional forces developed between the tube and tubesheet before any portion of the end-cap load is transmitted to the weld. Currently, all industry requests for a permanent H*/B* amendment have been withdrawn (see Section 2); however, the industry is still pursuing development of the information needed by the NRC staff to support future amendment requests for H*/B*.

The licensee has concluded that cracking exclusively in the weld is not a potential damage mechanism on the basis of the peer review findings. Should it not be possible for the NRC staff to approve an acceptable H*/B* amendment within a reasonable time period, it is the NRC staff's position that the industry will need to develop inspection techniques (e.g., visual, eddy-current) capable of detecting weld cracks to ensure that the welds are capable of performing their safety related function. It should be noted that the NRC staff observed a demonstration of an available visual inspection technique for inspecting the welds, but raised questions on whether this technique was sufficiently reliable.

5.0 FINAL NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

The Notice of Consideration of Issuance of Amendment to Facility Operating License and Proposed no Significant Hazards Consideration Determination, and Opportunity for Hearing for these amendments were published in the *Federal Register* on August 5, 2008 (73 FR 45485). Therefore, these amendments are being issued after the 30-day public comment period has expired, but before the 60-day hearing request period has expired.

The Commission may issue a license amendment before the expiration of the 60-day hearing period provided that its final determination is that the amendment involves no significant hazards consideration. Because these amendments are being issued prior to the expiration of the 60-day period, the NRC staff has made a final finding of no significant hazards consideration, which is given below.

In its application, the licensee made a determination that the amendment request involved no significant hazards consideration. Under the Commission's regulations in 10 CFR 50.92, this determination means that operation of the facility in accordance with the proposed amendment does not (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety. As required by 10 CFR 50.91(a), the licensee provided its analysis of the issue of no significant hazards consideration in Attachment I to its June 17, 2008, application, which is presented below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No

   Of the various accidents previously evaluated, the proposed changes only affect the steam generator tube rupture (SGTR), postulated steam line break (SLB), locked rotor and control rod ejection accident evaluations. Loss-of-coolant accident (LOCA) conditions cause a compressive axial load to act on the tube. Therefore, since the LOCA tends to force the tube into the tubesheet rather than pull it out, it is not a factor in this amendment request. Another faulted load consideration is a safe shutdown earthquake (SSE); however, the seismic analysis of Model D5 steam generators has shown that axial loading of the tubes is negligible during an SSE.

   At normal operating pressures, leakage from primary water stress corrosion cracking (PWSCC) below 17 inches from the top of the tubesheet is limited by both the tube-to-tubesheet crevice and the limited crack opening permitted by the tubesheet constraint. Consequently, negligible normal operating leakage is expected from cracks within the tubesheet region.

   For the SGTR event, the required structural margins of the steam generator tubes is maintained by limiting the allowable ligament size for a circumferential crack to remain in service to 203 degrees below 17 inches from the top of the tubesheet. Tube rupture is precluded for cracks in the hydraulic expansion region due to the constraint provided by the tubesheet. The potential for tube pullout is mitigated by limiting the allowable crack size to 203 degrees, which takes into account eddy current uncertainty and crack growth rate. It has been shown that a

circumferential crack with an azimuthal extent of 203 degrees meets the performance criteria of NEI 97-06, Rev. 2, "Steam Generator Program Guidelines" and the Draft Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes." Therefore, the margin against tube burst/pullout is maintained during normal and postulated accident conditions and the proposed change does not result in a significant increase in the probability or consequence of a SGTR.

The probability of a SLB is unaffected by the potential failure of a SG tube as the failure of a tube is not an initiator for a SLB event. SLB leakage is limited by leakage flow restrictions resulting from the leakage path above potential cracks through the tube-to-tubesheet crevice.

The leak rate during postulated accident conditions has been shown to remain within the accident analysis assumptions for all axial or circumferentially oriented cracks occurring 17 inches below the top of the tubesheet. Since normal operating leakage is limited to 0.10 gallons per minute (gpm) (or 150 gallons per day (gpd)), the attendant accident condition leak rate, assuming all leakage to be from indications below 17 inches from the top of the tubesheet would be bounded by 0.5 gpm. This value is within the accident analysis assumptions for the limiting design basis accident for Byron 2, which is the postulated SLB event.

Based on the above, the performance criteria of NEI-97-06, Rev. 2 and RG 1.121 continue to be met and the proposed change does not involve a significant increase in the probability or consequences of the applicable accidents previously evaluated (i.e., SLB, the locked rotor and control rod ejection accidents).

2. Does the proposed change create the possibility of a new or different accident from any accident previously evaluated?

   Response: No

   The proposed change does not introduce any changes or mechanisms that create the possibility of a new or different kind of accident. Tube bundle integrity is expected to be maintained for all plant conditions upon implementation of the interim alternate repair criterion. The proposed change does not introduce any new equipment or any change to existing equipment. No new effects on existing equipment are created nor are any new malfunctions introduced.

   Therefore, based on the above evaluation, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No

   RG 1.121 are used as the basis in the development of the interim alternate repair criteria (IARC) methodology for determining that steam generator tube integrity considerations are maintained within acceptable limits. RG 1.121 describes a method acceptable to the NRC staff for meeting General Design Criteria 14, 15,

31, and 32 by reducing the probability and consequences of an SGTR. RG 1.121 concludes that by determining the limiting safe conditions of tube wall degradation beyond which tubes with unacceptable cracking, as established by inservice inspection, should be removed from service or repaired, the probability and consequences of a SGTR are reduced. This RG uses safety factors on loads for tube burst that are consistent with the requirements of Section III of the ASME Code.

For axially oriented cracking located within the tubesheet, tube burst is precluded due to the presence of the tubesheet. For circumferentially oriented cracking in a tube or the tube-to-tubeshet weld, the Westinghouse analysis, provided in report "LTR-CDME-08-11 P-Attachment, Revision 3," supplemented by LTR-CDME-08-43 P-Attachment, Revision 3, defines a length of remaining tube ligament that provides the necessary resistance to tube pullout due to the pressure induced forces (with applicable safety factors applied). Additionally, it is shown that application of the IARC will not result in unacceptable primary-to-secondary leakage during all plant conditions, including transients and postulated accident conditions.

Based on the above, it is concluded that the proposed changes do not result in any reduction in a margin of safety.

The NRC staff has reviewed the licensee's analysis of no significant hazards consideration given above. The NRC staff finds that the licensee did not need to consider whether the requested amendments would increase the probability or consequences of the locked rotor or control rod ejection accidents because the licensee determined that the change would not increase the probability or consequences of the SLB accident and that the SLB is the limiting accident affected by the requested amendments.

Based on its review of the above analysis and the licensee's June 17, 2008, request, the NRC staff concludes that the three standards of 10 CFR 50.92 are satisfied. Therefore, the NRC staff has determined that the amendments involve no significant hazards consideration.

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Illinois State official was notified of the proposed issuance of the amendments. The State official had no comments.

7.0 ENVIRONMENTAL CONSIDERATION

The amendments change requirements with respect to installation or use of a facility's component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has made a final no significant hazards finding with respect to these amendments. Accordingly, these amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of these amendments.

8.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) the amendments do not (a) involve a significant increase in the probability or consequences of an accident previously evaluated; or (b) create the possibility of a new or different kind of accident from any accident previously evaluated; or (c) involve a significant reduction in a margin of safety; (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner; (3) such activities will be conducted in compliance with the Commission's regulations; and (4) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

Principal Contributor: A. Johnson, NRR

Date: October 1, 2008

October 1, 2008

Mr. Charles G. Pardee
President and Chief Nuclear Officer
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BYRON STATION, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENTS RE: REVISION TO TECHNICAL SPECIFICATIONS FOR THE STEAM GENERATOR PROGRAM (TAC NOS. MD9018 AND MD9019)

Dear Mr. Pardee:

The U.S. Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment No. 158 to Facility Operating License No. NPF-37 and Amendment No. 158 to Facility Operating License No. NPF-66 for the Byron Station (Byron), Unit Nos. 1 and 2, respectively. The amendments are in response to your application dated June 17, 2008.

The amendments revise Technical Specification (TS) 5.5.9, "Steam Generator (SG) Program," and TS 5.6.9, "Steam Generator (SG) Tube Inspection Report." For TS 5.5.9, the amendments incorporate a one-cycle interim alternate repair criteria in the provisions for SG tube repair criteria during Byron, Unit No. 2, refueling outage 14 and the subsequent operating cycle. For TS 5.6.9, the amendments revise the current reporting requirements. These changes only affect Byron, Unit No. 2; however, this action is docketed for both Byron units because the TS are common to both units.

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/RA/

Marshall J. David, Senior Project Manager
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. STN 50-454 and STN 50-455

Enclosures:
1. Amendment No. 158 to NPF-37
2. Amendment No. 158 to NPF-66
3. Safety Evaluation

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