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10 CFR 50
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10 CFR 54

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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Oyster Creek Generating Station
Facility Operating License No. DPR-16
NRC Docket No. 50-219

Subject: Response to NRC Request for Additional Information, dated March 20, 2006, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)

Reference: "Request for Additional Information for the Review of the Oyster Creek Nuclear Generating Station, License Renewal Application (TAC No. MC7624)," dated March 20, 2006

In the referenced letter, the NRC requested additional information related to Sections 3.1, B.1.9, and B.1.23 of the Oyster Creek Generating Station License Renewal Application (LRA). Enclosed are the responses to this request for additional information.

If you have any questions, please contact Fred Polaski, Manager License Renewal, at 610-765-5935.

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

Respectfully,

Executed on 04-18-2006

Michael P. Gallagher
Vice President, License Renewal
AmerGen Energy Company, LLC

Enclosure: Response to 03/20/06 Request for Additional Information

A114

cc: Regional Administrator, USNRC Region I, w/o Enclosure
USNRC Project Manager, NRR - License Renewal, Safety, w/Enclosure
USNRC Project Manager, NRR - License Renewal, Environmental, w/o Enclosure
USNRC Project Manager, NRR - OCGS, w/o Enclosure
USNRC Senior Resident Inspector, OCGS, w/o Enclosure
Bureau of Nuclear Engineering, NJDEP, w/Enclosure
File No. 05040

Enclosure

Response to 3/20/06 Request for Additional Information
Oyster Creek Generating Station
License Renewal Application (TAC No. MC7624)

RAI 3.1.1-1

(A) LRA Section 3.1.2.2.2 states that aging effects due to loss of material due to pitting and crevice corrosion in the isolation condenser will be managed by additional augmented inspections (i.e., eddy current testing (ET) of the stainless steel tubes and ultrasonic testing (UT) or visual testing (VT) of the tube sheet and channel head). During the telephone conference dated February 2, 2006, the applicant indicated that thus far no augmented inspections were performed on components associated with isolation condenser and that the proposed augmented inspections will be applicable as a part of an aging management program (AMP) during the extended period of operation. The staff requests the applicant to provide the following information so that an assessment can be made as to the effectiveness of the future augmented inspection program of the isolation condenser and its components.

(1) Previous experience related to the frequency of occurrence of pitting and crevice corrosion in the isolation condenser and its components.

(2) Previous inspection methods and the inspection frequency that were implemented prior to the replacement of some of the isolation condenser components.

(3) Criteria for establishing future augmented inspection frequency.

(B) LRA Section 3.1.2.2.4(3) states that aging effects due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC) will be managed by additional augmented inspections (i.e., ET of the stainless steel tubes and UT or VT of the tube sheet and channel head). During the telephone conference dated February 2, 2006, the applicant indicated that thus far no augmented inspections were performed on components associated with isolation condenser and that the proposed augmented inspections will be applicable as a part of an AMP during the extended period of operation. The staff requests the applicant to provide the following information so that an assessment can be made as to the effectiveness of the future augmented inspection program of the isolation condenser and its components.

(1) Previous experience related to the frequency of occurrence of SCC and IGSCC in the isolation condenser and its components.

(2) Previous inspection methods and the inspection frequency that were implemented prior to the replacement of some of the isolation condenser components.

(3) Criteria for establishing future augmented inspection frequency.

Response:

(A)(1) The carbon steel Isolation Condenser shells were fabricated with a nominal thickness of 0.375 inches, with a corrosion allowance of 0.100 inches. In 1996, NDE tests were performed on the Isolation Condenser "B" shell to determine the existence and extent of pitting corrosion. Plant experience has indicated that the condition of the "B" isolation condenser is the more limiting of the two condensers. The results of the NDE tests showed an average shell thickness of 0.389 inches with a standard deviation of 0.014 inches. In 2002, the "B" isolation condenser shell was again examined. Visual examination results indicated blistering of the coating at or near the waterline. NDE results from tests performed at locations just below the waterline (judged to have the highest probability for accelerated corrosion) yielded readings well within the control limits computed from the 1996 readings, and above or close to the fabrication nominal thickness of 0.375 inches.

Prior to tube bundle replacement in the Oyster Creek isolation condensers, the stainless steel tube bundles were found to be subject to crevice corrosion. Tube OD crevice corrosion located in the crevice formed by the roll expansion process during tube bundle fabrication was accelerated by elevated isolation condenser temperatures due in part to condensate return valve leakage. In addition, numerous thermal cycles were caused by isolation condenser water level oscillation due to the valve leakage condition, and system service as the primary heat sink during reactor shutdowns employing opening and closing of the condensate return valves as needed to limit cooldown rate. Subsequent correction of the condensate return valve leakage condition and changes to isolation condenser operation strategy during reactor cooldown have significantly reduced the thermal cycling that exacerbated the crevice corrosion conditions which existed in the original tube bundle assemblies.

(A)(2) In 1996 and again in 2002, VT and UT inspection methods were used to evaluate the condition of the isolation condenser shell.

During the evaluation of the isolation condenser tube leakage conditions, UT and thermography testing were used to determine the condensate/steam interface in the isolation condensers, and acoustic monitoring of boiling intensity was used to determine the presence of stratified tube internal conditions.

Weekly temperature monitoring of isolation condenser temperature and monthly radioactivity sampling of the shell water (subsequently changed to weekly) has been performed since before tube bundle replacement.

(A)(3) Correction of the valve leakage condition has significantly reduced the number of isolation condenser water level oscillations and resultant thermal cycles applied to the isolation condenser components. The Oyster Creek isolation condenser tube bundles were replaced in the "A" isolation condenser in 2000 and in the "B" isolation condenser in 1998, utilizing improved materials that are more resistant to intergranular stress corrosion cracking. Due to the physical configuration of the isolation condensers and piping at Oyster Creek, eddy current inspection of the tubes and access to the tubesheet and internal surfaces of the channel head require cutting and re-welding of pressure boundary piping. Because of the significant reduction in frequency of initiating conditions, and the relatively recent replacement of the tube bundles with improved materials, these inspections will be performed once during the first ten years of the period of extended operation. Radioactivity and temperature monitoring of the shell side water as specified in the GALL recommendations for isolation condenser aging management are currently being performed weekly and will continue throughout the period of extended operation. Additionally, during the NRC Region 1 Inspection, AmerGen has committed to performing a one-time UT inspection of the "B" Isolation Condenser shell for pitting corrosion, prior to the period of extended operation. Plant experience has indicated that the condition of the "B" isolation condenser is the more limiting of the two condensers. This commitment will be added to the Table A.5 License Renewal Commitment List Item No. 24.

(B)(1) Prior to tube bundle replacement in the Oyster Creek isolation condensers, the stainless steel tube bundles were found to be subject to stress corrosion cracking. Fatigue-propagated cracks on the OD surface of the tubes initiated by trans-granular stress corrosion cracking, and fatigue cracks at the seal weld and portions of the tubesheet adjacent to the seal weld were caused by oscillating conditions internal to the tubes due to condensate return valve leakage. Numerous thermal cycles were caused by isolation condenser water level oscillation due to the valve leakage condition, and system service as the primary heat sink during reactor shutdowns employing opening and closing of the condensate return valves as needed to limit cooldown rate. Subsequent correction of the condensate return valve leakage condition and changes to isolation condenser operation strategy during reactor cooldown have significantly reduced the thermal cycling that exacerbated the stress corrosion cracking conditions which existed in the original tube bundle assemblies.

(B)(2) During the evaluation of the isolation condenser tube leakage conditions, UT and thermography testing were used to determine the condensate/steam interface in the isolation condensers, and acoustic monitoring of boiling intensity was used to determine the presence of stratified tube internal conditions. Weekly temperature monitoring of isolation condenser temperature and monthly radioactivity sampling of the shell water (subsequently changed to weekly) has been performed since before tube bundle replacement.

(B)(3) Correction of the valve leakage condition has significantly reduced the number of isolation condenser water level oscillations and resultant thermal cycles applied to the isolation condenser components. The Oyster Creek isolation condenser tube bundles were replaced in the "A" isolation condenser in 2000 and in the "B" isolation condenser in 1998, utilizing improved materials that are more resistant to intergranular stress corrosion cracking. Due to the physical configuration of the isolation condensers and piping at Oyster Creek, eddy current inspection of the tubes and access to the tubesheet and internal surfaces of the channel head require cutting and re-welding of pressure boundary piping. Because of the significant reduction in frequency of initiating conditions, and the relatively recent replacement of the tube bundles with improved materials, these inspections will be performed once during the first ten years of the period of extended operation. Radioactivity and temperature monitoring of the shell side water as specified in the GALL recommendations for isolation condenser aging management are currently being performed weekly and will continue throughout the period of extended operation. Additionally, during the NRC Region I Inspection, AmerGen has committed to performing a one-time UT inspection of the "B" Isolation Condenser shell for pitting corrosion, prior to the period of extended operation. Plant experience has indicated that the condition of the "B" isolation condenser is the more limiting of the two condensers. This commitment will be added to the Table A.5 License

Renewal Commitment List Item No. 24.

RAI 3.1.1-2

Item 3.1.1-33 in LRA Table 3.1.1 indicates that the AMP for the RPV inside diameter (ID) attachment welds comply with the recommendations specified in AMP-B.1.4, "BWR Inside Diameter Attachment Welds Program." LRA AMP-B.1.4 states that the frequency and the method of inspection specified in the BWRVIP-48, "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines" report will be implemented for the attachment welds. These guidelines apply to core spray piping bracket attachments, steam dryer support and hold down brackets, feedwater spargers, guide rod, and surveillance sample holder. According to the BWRVIP-48 report Section 2.2.3, furnace-sensitized stainless steel vessel ID attachment welds are highly susceptible to IGSCC. The staff requests the applicant to identify whether there are any furnace-sensitized stainless steel attachment welds at the OCN unit, and explain what type of AMP is implemented for any existing furnace-sensitized stainless steel attachment welds. The staff also requests the applicant to provide details on any additional augmented inspection program that is implemented for any existing furnace-sensitized stainless steel attachment welds at the OCN unit.

Response:

The bracket materials and Inconel attachment welds at Oyster Creek were determined to have been furnace-sensitized during vessel fabrication. However, no flaw indications have been reported for these attachment welds at Oyster Creek. The Oyster Creek BWR Vessel ID Attachment Welds aging management program provides for identification, evaluation and mitigation of cracking by water chemistry control and periodic examinations. The scope of the program includes the steam dryer support lugs, guide rod wall bracket, feedwater sparger bracket, and surveillance sample holder bracket. The core spray piping to vessel attachment welds are inspected accordance with BWRVIP-18-A as part of the Oyster Creek Reactor Internals aging management program.

The program includes measures to mitigate IGSCC by ensuring the water chemistry recommendations of BWRVIP-130 are used in the station's water chemistry program. The reactor water chemistry program monitors and controls known detrimental contaminants such as chlorides, dissolved oxygen, and sulfate concentrations in accordance with the recommendations of the BWRVIP-130. BWRVIP-130 (EPRI TR-1008192) replaces BWRVIP-29, the previous EPRI water chemistry standard.

The station's in-vessel examination programs inspect for and monitor the effects of cracking . The inspections to be performed at each refueling outage are determined by a review of the requirements in BWRVIP-48-A and ASME Section XI.IWB-2400, and from a review of past operating experience. Specifically, inspections of the vessel ID brackets and their attachments to the vessel ID are currently performed by the Oyster Creek ASME Section XI program under examination category B-N-2 ("Interior Attachments to the Reactor Vessel"). These ASME Section XI visual inspections use examination methods VT-1 and VT-3 to detect discontinuities and imperfections on the surfaces of components and to determine the general mechanical and structural condition of the component supports. BWRVIP-48-A maintains the inspection frequency per ASME Section XI Examination Category B-N-2 and recommends more stringent inspection techniques for certain selected attachments. All of these welds are inspected using both VT-3 and Enhanced VT-1 methods. All of the core spray piping brackets are inspected using Enhanced VT-1 every four cycles. The inspection method and frequency of the core spray components in the RPV are discussed in the response to RAI B.1.9-4. There are no additional augmented inspections for the reactor vessel internal attachment welds.

RAI 3.1.1-3

(A) Item 3.1.1-6 in LRA Table 3.1.1 indicates that augmented inspection for the CRD return line weld is required in accordance with NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking" at the OCN unit. NUREG-0619 recommends a periodic liquid penetrant test (PT) to evaluate the aging effect due to IGSCC in the CRD return line weld. The applicant in AMP B.1.6, "BWR Control Rod Drive Return Line Nozzle," states that it obtained approval from the staff to substitute UT for PT as a part of the augmented inspection program and this approval is valid only for the current in-service inspection (ISI) interval. Therefore, the staff requests that the applicant provide justification for continuing UT inspections in lieu of PT for the subject weld during the extended period of operation.

(B) The staff requests the applicant to provide information whether the CRD return line nozzle has been capped at the OCN unit. If the CRD return line nozzle has been capped, the staff requests the applicant to provide the following information regarding the cap and the weld:

(1) Describe the configuration, location and material of construction of the capped nozzle. This should include the existing base material for the nozzle, piping (if piping remnants exist) and cap material, and any welds.

(2) Describe how this weld and cap is managed in accordance with the guidelines of BWRVIP-75, "BWR Vessel and Internals Project (BWRVIP), Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedule."

(3) Discuss whether the event at Pilgrim (leaking weld at capped nozzle, September 30, 2003) is applicable to OCN unit. The staff issued Information Notice 2004-08, "Reactor Coolant Pressure Boundary Leakage Attributable to Propagation of Cracking in Reactor Vessel Nozzle Welds" dated April 22, 2004, which states that the cracking occurred in a 182 weld that was previously repaired extensively. Discuss any plant experience with previous leakage at the capped nozzle. Include in your discussion the past inspection techniques applied, the results obtained, and mitigative strategies imposed. Provide information as to how the plant-specific experience related to this aging effect impacts the attributes specified in AMP-B.1.6.

Response

(A) The approval granted by the NRC in 1992 to inspect the CRD nozzle using UT in lieu of PT examination methodology has no time limit. This approval was not a relief to the ISI program in accordance with 10 CFR 50.55a and therefore does not expire with the 10-year ISI interval. The CRD RL nozzle will be inspected by UT techniques using the latest Performance Demonstration Initiative (PDI) technology available at the time at the inspections. Use of modern UT examination methods will continue to provide equivalent or improved means of detecting cracks in the CRD nozzle compared to the methods available when the NRC approved use of UT methods for this nozzle in 1992. Using PT examinations is much more difficult to perform since the vessel has to be drained and the thermal sleeve would have to be removed to access to the nozzle interior, resulting in signiifcant radiation personnel exposure.

(B) Because the CRD return line has not been capped, questions B (1), B (2), and B (3) are not applicable to Oyster Creek. The nozzle was modified by installing an improved thermal sleeve design inside the nozzle bore. The Oyster Creek CRD Return Line Nozzle program, B.1.6, manages the effects of cracking in the CRD nozzle.

RAI 3.1.1-4

(A) The AMP B.1.5, references GE report GE-NE-523-A71-0594, "Alternate BWR Feedwater Nozzle Inspection Requirements," which is not the Nuclear Regulatory Commission (NRC) approved version of the report. The staff requests the applicant to confirm if OCN will implement the recommendations of Revision 1, Version A of the report (GE-NE-523-A71-0594-A, Revision 1), which is approved by the staff.

(B) The staff requests the applicant to identify whether the dissimilar metal welds of RPV nozzles, safe end components and piping have previously experienced cracking due to SCC, IGSCC or cyclic loading and the extent of cracking. The applicant should provide information regarding the extent of mitigative techniques [i.e., structural overlay, mechanical stress improvement (MSIP)] that were implemented to mitigate crack propagation due to IGSCC in the dissimilar metal welds between RPV nozzles and safe ends, and welds between safe ends and piping. In addition, the applicant should provide information on the inspection methods, sample size, and the frequency of inspections that were used thus far in these welds and the inspection results. The applicant should provide its basis for using the current inspection program as an effective AMP in monitoring the aging effect due to IGSCC in the aforementioned welds.

Response

(A) Oyster Creek will implement the recommendations of the BWROG Topical Report, GE-NE-523-A71-0594, Revision 1, Version A, prior to the period of extended operation. Item number 5 of LRA Table A.5 will be updated to reflect this commitment.

(B) There have been no cracks identified on the dissimilar metal welds associated with the RPV nozzles, safe end components, or welds between safe ends and piping at Oyster Creek. Several mitigative actions have been taken for the vessel nozzle dissimilar welds, including Induction Heating Stress Improvement (IHSI), Mechanical Stress Improvement Process (MSIP), hydrogen water chemistry (HWC), and noble metals chemical addition (NMCA). Specifically, The A, B, D, and E recirculation inlet and outlet vessel nozzles have had MSIP applied in 1994. IHSI has been applied to the C Recirc inlet and outlet RPV nozzles, the A and B Core Spray vessel nozzles, and the Isolation Condenser steam outlet nozzles in 1988. The feedwater and main steam vessel nozzles are attached to carbon steel piping and do not have dissimilar-metal welds. The Oyster Creek water chemistry program is an important aspect of its IGSCC mitigation strategy. The Oyster Creek water Chemistry program follows the latest EPRI water chemistry guidelines. In addition to MSIP and IHSI the Oyster Creek implemented hydrogen water chemistry (HWC) in 1992. In 2002 applied the first application of noble metals as part of the NMCA program.

All nozzle and safe end dissimilar welds are inspected every ten years in accordance with ASME Section XI, Table 2500-1, Category B-F, using volumetric (UT) and surface examination techniques. The above measures demonstrate that the current inspection program for vessel nozzles and safe ends will provide reasonable assurance the effects of cracking due to SCC and IGSCC for the dissimilar metal welds will be adequately managed in the period of extended operation.

RAI 3.1.1-5

Item 3.1.1-43 in LRA Table 3.1.1 indicates that cast austenitic stainless steel (CASS) components are used for orificed fuel support components. The staff requests the applicant to provide the following information on this component so that assessment can be made as to its susceptibility to thermal and neutron irradiation embrittlement.

(a) Information on type of casting (i.e., centrifugal or static)

(b) The composition of CASS (i.e., molybdenum content and delta ferrite values)

(c) Previous plant-specific experience regarding the cracked components and type and extent of subsequent inspection of CASS orificed fuel support components due to neutron and thermal embrittlement. The fluence values should be based on the end of the extended period of operation.

Response

The aging management program for Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless steel (CASS) is a new program that will provide for aging management of CASS reactor internal components within the scope of license renewal. The program includes a component-specific evaluation to identify the "susceptible components" determined to be limiting from the standpoint of thermal aging susceptibility (i.e., ferrite and molybdenum contents, casting process, and operating temperature) and/or neutron irradiation embrittlement (neutron fluence). For each "potentially susceptible" component, the program specifies that either a supplemental examination of the affected component exposed to temperatures greater than 482 °F and/or to a fluence greater 10^{17} n/cm^2 during the period of extended operation will be performed, or a detailed component-specific evaluation will be performed to determine its susceptibility to loss of fracture toughness.

(a) The component-specific evaluations will be performed prior to the period of extended operation, but the specific materials information needed for these evaluations has not yet been obtained.

(b) See (a)

(c) The fuel support castings are potentially subject to aging embrittlement from exposure to high temperatures and neutron fluence. However, as indicated in BWRVIP-47, there is no record of cracking in orificed fuel support castings in any BWR. Oyster Creek has visually examined fuel support castings, when inspection opportunities existed, and have not detected any cracking in the fuel support castings to date.

The fluence values used to evaluate components potentially susceptible to high temperature and/or neutron fluence embrittlement will be based on the maximum fluence predicted to occur during the period of extended operation.

RAI 3.1.2.1-1

(A) In LRA Table 3.1.2.1.5, the applicant states that it will implement ASME Section XI, ISI program to monitor carbon steel (SA 105 Grade II) cracking in the following RPV components:

(1) Bottom head drain nozzle;
(2) Feedwater and main steam nozzles and safe ends;
(3) Core spray nozzle;
(4) Isolation condenser nozzle;
(5) Top head nozzles;
(6) Top head flange;
(7) Bottom head flange;
(8) RPV shell welds and,
(9) Reactor head cooling.

The staff requests the applicant to provide the following information related to the subject aging effect in the aforementioned carbon steel components:

(a) Previous plant experience related to cracking in carbon steel RPV components when exposed to treated water.

(b) Established mechanism of the cracking in carbon steel RPV components.

(c) The scope and the techniques of the past inspections, the results obtained, applied mitigative methods, repairs, frequency of the inspections and any other relevant information related to the identification of the subject aging effect.

(B) The staff requests the applicant to address whether there was any previous plant experience related to cracking (not due to SCC or IGSCC) in carbon steel valve bodies of the reactor head cooling system, when exposed to treated water (Table-3.1.2.1.3).

Response

(A) Reactor Pressure Vessel carbon steel components exposed to treated water:

(a) The only carbon steel component in the Oyster Creek reactor vessel that has experienced cracking is the feedwater nozzles. In 1977 Oyster Creek inspected the feedwater nozzles in response to industry operating experience. Cracks were found in the feedwater nozzles that required repair. The stainless steel cladding was removed, the cracks were removed from the nozzle blend radius, and an improved sparger/thermal sleeve design was installed. No other cracking has been experienced in carbon steel RPV components at Oyster Creek.

(b) The degradation mechanism that applies to the cracking found in the Oyster Creek carbon steel RPV components was thermal fatigue.

(c) Scope of past inspections includes:

(1) Feedwater and main steam nozzles and safe ends;
(2) Core spray nozzle;
(3) Isolation condenser nozzle;
(4) Top head nozzles;
(5) Top head flange;
(6) Vessel shell flange; and,
(7) RPV shell welds.

These components are inspected as Category B-A Pressure Retaining Welds in Reactor Vessels or Category B-D Full Penetration Welded Nozzles in Vessels. Section XI requires UT examination of these welds and the nozzle inner radius once every 10 years.

Examination results have been acceptable; no cracking has been identified in the nozzles with the exception of the feedwater nozzle discussed above. Several mitigation actions were taken to reduce the susceptibility of feedwater nozzle to cracking, including replacing the thermal sleeves with an improved design, removing the stainless steel cladding and improving feedwater flow control to eliminate on/off cycling at low power.

The bottom head drain nozzle is not inspected because it is smaller than the minimum size that requires an UT examination by ASME Section XI; and it is very difficult to examine because of its location.

(B) Head Spray Cooling System: The reactor head cooling system valves are stainless steel exposed to the environment of treated water; no cracking has been identified in these valves.

RAI 3.1.2.1-2

Table IV.B1, item IV.B1-15, of the GALL Report, Volume 2, Revision 1, recommends implementation of AMP B.1.1, "ASME Section XI, Inservice Inspection Subsections IWB, IWC, and IWD," and AMP B.1.2, "Water Chemistry," to manage aging effects due to loss of material, pitting and crevice corrosion in stainless steel and nickel-alloy materials in the reactor vessel internal (RVI) components. Since this is not included in LRA Table 3.1.2.1.4, the staff requests that the applicant address these aging effects in LRA Table 3.1.2.1.4.

Response

NUREG-1801, Volume 2, Revision 1, Table IV.B1, item IV.B1-15 is a new line item for Reactor Vessel Internal Components, compared to the January revision of NUREG 1801(GALL). Oyster

Creek already manages the effects of cracking in reactor internals using Water Chemistry and inspections through its Reactor Vessel Internals program (B.1.9). Oyster Creek will revise its Reactor Internals program to also manage the aging effect of loss of material due to the aging mechanisms of pitting and crevice corrosion for Reactor Internals. Inspections and Water Chemistry will ensure the effect of loss of material due to the aging mechanisms of pitting and crevice corrosion for reactor internals are adequately managed. Item number 9 of LRA Table A.5 will be revised to add this new inspection requirement to the Reactor Internals program.

<u>**RAI B.1.9-1**</u>

RAI-AMP B.1.9-1(A) - In the final safety analysis report (FSAR) supplement A.1.9, "BWR Vessel Internals," the applicant states that the BWR vessel internals program is consistent with the BWRVIP-94, "BWR Vessels and Internals Project, Program Implementation Guideline" report. The staff requests the applicant to revise AMP B.1.9 to reference the BWRVIP-94 report, and include the following issues related to the scope of the implementation of the BWRVIP-94 guidelines in AMP B.1.9:

(1) The applicant shall inform the staff of any decision to not fully implement a BWRVIP guideline approved by the staff within 45 days of the report.

(2) The applicant shall notify the staff if changes are made to the RPV and its internals' programs that affect the implementation of the BWRVIP guidelines.

(3) The applicant shall submit any deviation from the existing flaw evaluation guidelines that are specified in the BWRVIP report.

<u>Response</u>

AmerGen/Exelon is committed to following BWRVIP guidelines. While the above three policies are not explicitly stated in the LRA, these statements are existing commitments included in our corporate and station procedures regarding compliance with BWRVIP guidelines. Specifically:

(1) Oyster Creek will inform the staff of any decision to not fully implement a BWRVIP guideline approved by the staff within 45 days of the report.

(2) Oyster Creek will notify the staff if changes are made to the RPV and its internals' programs that affect the implementation of the BWRVIP guidelines.

(3) Oyster Creek will submit any deviation from the existing flaw evaluation guidelines that are specified in the BWRVIP report.

A new LRA Table A.5 commitment will be created to reflect the above policy regarding compliance to BWRVIP guidelines.

<u>**RAI B.1.9-2**</u>

The BWRVIP-76, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines" and BWRVIP-104, "Evaluation and Recommendations to Address Shroud Support Cracking in

BWRs" reports are currently being reviewed by the staff. The staff requests the applicant to make a commitment that it will comply with all the recommendations that will be specified in the staff's final safety evaluations (SEs) of these reports, and that it will complete all the license renewal action items in the final SEs when they are issued.

Response

Oyster Creek will comply with all the applicable requirements that will be specified in the staff's final safety evaluations (SEs) of the BWRVIP-76 and BWRVIP-104 reports, and that it will complete all the license renewal action items in the final SEs applicable to Oyster Creek, when they are issued. Item number 9 of LRA Table A.5 will be revised to reflect this commitment.

RAI B.1.9-3

The applicant states that two leaking CRD stub tubes were repaired by using a roll expansion method which was approved by the staff on November 16, 2000, for one refuel cycle only. The applicant further states that this repair was submitted to the ASME Code in form of draft ASME Section XI Code Case N-730, "Roll-Expansion of Class 1 Control Rod Drive Bottom Head," for review and approval. The applicant intends to apply this repair on a permanent basis at the OCN unit when Code Case N-730 is approved by the ASME Code and the NRC. If Code Case N-730 is not approved, the applicant shall submit a permanent repair plan to the staff for review and approval two years prior to the commencement of the extended period of operation. After the implementation of an approved permanent roll repair, if there is a leak in CRD stub tubes, the applicant shall commit to immediately repair any leaking CRD stub tubes during the extended period of operation by implementing a permanent weld repair per the approved ASME Section XI Code Cases with staff conditions, if any.

The staff requests the applicant to revise AMP B.1.9 and FSAR supplement A.1.9 to commit to implementing a staff-approved permanent repair as stated above, which will result in no leakage of the CRD of the stub tubes during the extended period of operation.

Response

If Code Case N-730 is not approved, Oyster Creek will develop a permanent ASME code repair plan. This permanent ASME code repair could be performed in accordance with BWRVIP-58-A, which has been approved by the NRC, or an alternate ASME code repair plan which would be submitted for prior NRC approval. If it is determined that the repair plan needs prior NRC approval, Oyster Creek will submit the repair plan two years before entering the period of extended operation.

After the implementation of an approved permanent roll repair (draft code case N-730), if there is a leak in a CRD stub tube, Oyster Creek will weld repair any leaking CRD stub tubes during the extended period of operation by implementing a permanent NRC approved ASME Code repair for leaking stub tubes that cannot be made leak tight using a roll expansion method prior to restarting the plant. Appendix A.1.9 and item number 9 of Table A.5 will be updated to reflect the above commitments.

RAI B.1.9-4

The applicant states that recent inspections of core spray spargers and core spray piping welds indicated that the mitigation techniques have been proven to be effective in minimizing the crack growth rates due to IGSCC in the subject components. The staff requests the applicant to provide further information on its future inspection plans which include the type and frequency of inspections, inspection methods, sample size, and inspection frequency for the repaired and non-repaired core spray components during the extended period of operation.

Response

Oyster Creek inspects the core spray spargers and piping welds in accordance with the BWRVIP-18-A requirements as described below.

Baseline Inspections

Baseline inspections were performed as the first inspections to satisfy the BWRVIP-18-A guidelines, even though some were performed prior to formal issuance of the guideline. The core spray piping baseline was performed on all circumferential piping welds using visual examination methods. The inspections were performed using the following types of visual exams.

- The piping brackets were inspected by EVT-1 per Table 3-2 of BWRVIP-18-A.
- The sparger welds S1, S2, and S4 were inspected by EVT-1.
- The sparger nozzle S3 welds were inspected by VT-1.
- The sparger brackets were inspected by VT-1.

The purpose of the baseline inspections of the repair was to confirm the integrity of the repair. At Oyster Creek all four of the sparger tee boxes have repair clamps installed. These clamps provide the structural integrity for the sparger piping at these locations and as such the S1 and S2 welds identified in BWRVIP-18-A do not need to be inspected. The sparger repair clamps are of a bolted design and require a VT-1 inspection every two cycles to assure that the bolts have not backed out.

Reinspection (including period of extended operation):

Piping reinspections are performed every refueling cycle, since the baseline was performed visually. The reinspection sample includes all creviced welds with existing flaws, and a rotating sample of 25% of the piping butt welds, such that four reinspections would cover all welds. The reinspection for the sparger is performed using the same visual techniques used for the baseline. The scope includes any previously cracked locations and a rotating 25% sample of the sparger welds. Again, all accessible welds are inspected after four inspections.

Reinspection of piping brackets utilizes the EVT-1 examination method, and reinspection of sparger brackets utilizes a VT-1 examination method. If no cracking is detected, then reinspection of all welds every four cycles (25% rotating sample) is sufficient. If cracking is detected, then reinspection frequency of the flawed location and other locations will be based on the flaw evaluation.

RAI B.1.9-5

The applicant states that recent inspections of the core shroud repair tie rods indicated that the repair techniques are effective in minimizing the crack growth rates in the subject component. The staff requests the applicant to provide information on its future inspection plans such as type and frequency of inspections and percentage of the core shroud tie rods that are currently being inspected. If the inspection sample size is not consistent with the BWRVIP-76 guidelines, the applicant should provide an explanation for this inconsistency. The staff also requests that the applicant provide its plans regarding the inspection plans (i.e., inspection methods, sample size, and inspection frequency) of non-repaired core shroud welds during the extended period of operation.

Response

The Oyster Creek Reactor Internals program follows BWRVIP-76 guidelines for inspection of the core shroud. The program inspects 100% of the 10 shroud repair tie rods every 10 years with VT-3 consistent with the BWRVIP-76 requirements. In addition, the program specifies inspection of all of the tie rod repair anchorage points (Lug-clevis assemblies) every 10 years using an EVT-1 examination.

The horizontal shroud welds are not inspected since they are repaired with clamps, in accordance with the guidelines of BWRVIP-76. Oyster Creek will continue to inspect all accessible Core Shroud non-repaired (vertical) welds in accordance with BWRVIP-76 requirements (UT or VT) every 10 years.

RAI B.1.9-6

The staff requests the applicant to provide information regarding the type of plugs (i.e., spring-loaded plugs or welded plugs) that were used for plugging the core plate holes at the OCN unit. If spring-loaded core plate plugs were used at the OCN unit, the applicant should provide the type of AMP that is implemented to ensure their integrity.

Response

The Oyster Creek core plate does not have flow holes drilled in the core plate, as exist in some BWR 3 and BWR4 plants.

RAI B.1.9-7

The staff requests the applicant to provide information whether any noble metal chemical application (NMCA) is applied at the OCN unit. Confirm the method of controlling hydrogen water chemistry and any NMCA as a mitigative method to reduce the IGSCC

susceptibility in the RVI components. Provide details on the methods for determining the effectiveness of hydrogen water chemistry and/or NMCA by using the following parameters:

(1) Electro Chemical Potential (ECP)
(2) Feedwater hydrogen flow
(3) Main steam oxygen content
(4) Hydrogen/oxygen molar ratio.

Response

Hydrogen Water Chemistry (HWC) and Noble Metal Chemical Addition (NMCA) were implemented at Oyster Creek in 1992 and 2002, respectively.

HWC control is established by monitoring and maintaining the Hydrogen/Oxygen molar ratio and ECP within the guidelines established in BWRVIP-130 in the reactor water. For NMCA noble metal concentrations are monitored and reapplication of Noble Metals is scheduled when the Pt/Rh concentration is predicted to fall below established limits.

The guidelines in BWRVIP-130 for BWR reactor water recommend that the concentration of chlorides, sulfates, and dissolved oxygen are monitored and kept below the recommended levels to mitigate corrosion. The two impurities, chlorides and sulfates, determine the coolant conductivity; dissolved oxygen, hydrogen peroxide, and hydrogen determine electrochemical potential (ECP). The EPRI guidelines recommend that the coolant conductivity and ECP are also monitored and kept below the recommended levels to mitigate SCC and corrosion in BWR plants. Oyster Creek monitors ECP directly with ECP probes in the B Recirculation Loop, via the RWCU system. Oyster Creek uses reactor water dissolved oxygen as a secondary parameter to ensure that mitigation is maintained in the recirculation loops. Several parameters are monitored to ensure ECP and oxygen levels are maintained within established guidelines. The hydrogen concentrations in the feedwater are monitored daily. Calculated hydrogen flow rates are established to maintain Hydrogen and oxygen levels in the vessel within guidelines developed from BWRVIP-130. The hydrogen and oxygen molar ratio is maintained greater than or equal to 3.0 to ensure proper ECP levels and NMCA effectiveness. The oxygen levels in the main steam are not monitored, since oxygen levels are measured directly in the reactor coolant as a means of maintaining chemistry control.

RAI B.1.9-8

The staff requests the applicant to address how it will use AMP B.1.9 to monitor aging due to loss of material due to pitting and crevice corrosion and aging degradation due to SCC and IGSCC in non-safety related RVI components (i.e., steam dryer, core shroud heads and separators, internal feedwater spargers, and RPV surveillance capsule holders).

Response

The Oyster Creek Rx internals program monitors non-safety related internal components in addition to the safety-related internal components. In Appendix A.1.9 and B.1.9 of the LRA Oyster Creek committed to inspect the steam dyer in accordance with the guidelines of BWRVIP-139. BWRVIP inspections will begin in 2008. The feedwater spargers are inspected in accordance with the requirements of NUREG 0619. Oyster Creek also inspects the steam separator and shroud head, and the core inlet flow baffle (diffuser) in the lower head region for degradation. The Reactor Internals program will be enhanced to include inspection for loss of material for the feedwater sparger, steam separator, RPV surveillance capsule holders and baffle plate. Item number 9 of Table A.5 will be updated to reflect the above commitments.

RAI B.1.9-9

The NRC staff has approved the applicable BWRVIP reports and attached the following required license renewal applicant action items, in accordance with 10 CFR Part 54, when incorporating the reports in a license renewal application.

The applicant is to verify that its plant is bounded by cited BWRVIP reports. Further, the applicant is to commit to programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operation. Applicants will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the AMPs within these BWRVIP reports described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the components or other information presented in the reports, such as materials of construction, will have to be identified by the applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).

10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants referencing the applicable BWRVIP reports shall ensure that the programs and activities specified as necessary in the applicable BWRVIP reports are summarily described in the FSAR supplement.

10 CFR 54.22 requires that each application include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. The applicable BWRVIP reports may state that there are no generic changes or additions to technical specifications associated with the reports as a result of the applicant's aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those referencing the applicable BWRVIP reports shall ensure that the inspection strategy described in the reports does not conflict with, or result in, any changes to their technical specifications. If technical specifications changes do result, then the applicant must ensure that those changes are included in its application for license renewal.

If required by the applicable BWRVIP report, the applicant referencing a particular report for license renewal should identify and evaluate any potential TLAA issues and/or commitments to perform future inspections when inspection tooling is made available.

Provide the necessary commitments, information and changes as described above for each of the following applicable BWRVIP reports:

BWRVIP-05, "Reactor Vessel Shell Weld Inspection Guidelines."

BWRVIP-18, "BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines."

BWRVIP-25, "BWR Core Plate Inspection and Flaw Evaluation Guidelines."

BWRVIP-26, "BWR Top Guide Inspection and Flaw Evaluation Guidelines."

BWRVIP-27-A, "BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines."

BWRVIP-38, "BWR Shroud Support Inspection and Flaw Evaluation Guidelines."

BWRVIP-47, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines."

BWRVIP-48, "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines."

BWRVIP-49, "Instrument Penetration Inspection and Flaw Evaluation Guidelines."

BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines."

BWRVIP-75, "BWR Vessel and Internals Project (BWRVIP), Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedule."

BWRVIP-76, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines."

BWRVIP-78, "BWR Integrated Surveillance Program (ISP) Plan."

BWRVIP-86, "BWR Vessel and Internals Project, BWR Integrated Surveillance Program Implementation."

Other reports applicable to license renewal.

<u>Response</u>

Appendices A.1.9 and B.1.9 of the Oyster Creek LRA provide a list of BWRVIP guidelines that are implemented by the Oyster Creek aging management programs. These are:

BWRVIP-18-A "BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines."
BWRVIP-25, "BWR Core Plate Inspection and Flaw Evaluation Guidelines."
BWRVIP-26, "BWR Top Guide Inspection and Flaw Evaluation Guidelines."
BWRVIP-27-A, "BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines."
BWRVIP-38, "BWR Shroud Support Inspection and Flaw Evaluation Guidelines."
BWRVIP-47, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines."

BWRVIP-48, "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines."
BWRVIP-49, "Instrument Penetration Inspection and Flaw Evaluation Guidelines."
BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines."
BWRVIP-76, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines."
BWRVIP-104, "Evaluation and Recommendations to Address Shroud Support Cracking in BWRs."

In addition to the BWRVIP guidelines listed above, compliance with BWRVIP-75 is stated in Appendix A1.7, "BWR Stress Corrosion Cracking aging management program", in the LRA. Likewise, compliance with BWRVIP-78 and BWRVIP-86 is stated in Appendix A.1.23.

BWRVIP-05 provides recommendations for alternative inspections requirements for reactor vessel beltline shell welds. Oyster Creek has followed the methodology recommended in BWRVIP-05 to justify relief requests that eliminate circumferential weld inspections and reduce the RPV vertical weld inspection scope. These justifications are considered TLAAs for license renewal and are evaluated for the period of extended operation using the BWRVIP-05 methodology in Sections 4.2.4 and 4.2.5 of the LRA.

The following table provides a cross-reference between BWRVIP guidelines used at Oyster Creek and the appropriate aging management program that implements the recommendations of the BWRVIP guideline.

Specific BWRVIP Guidelines Implemented by Oyster Creek Aging Management Programs

BWRVIP Guideline	OC Aging Management Program
BWRVIP-05	TLAA, LRA Section 4.2
BWRVIP-18-A	B.1.9
BWRVIP-25	B.1.9
BWRVIP-26	B.1.9
BWRVIP-27-A	B.1.9
BWRVIP-47	B.1.9
BWRVIP-48	B.1.4
BWRVIP-49	B.1.8, B.1.9
BWRVIP-74-A	B1.9, TLAA, LRA Section 4.2
BWRVIP-76	B.1.9
BWRVIP-104	B.1.9
BWRVIP-75	B.1.7
BWRVIP-78	B.1.23
BWRVIP-86	B.1.23
BWRVIP-116	B.1.23
BWRVIP-130	B.1.2, B.1.4, B.1.7, B.1.8, B.1.9, B.1.18

Amergen/Exelon is committed to following all applicable BWRVIP guidelines. Implementing procedures direct that:

1. Oyster Creek will inform the staff of any decision to not fully implement a BWRVIP guideline approved by the staff within 45 days of the report.
2. Oyster Creek will notify the staff if changes are made to the RPV and its internals' programs that affect the implementation of the BWRVIP guidelines.
3. Oyster Creek will submit any deviation from the existing flaw evaluation guidelines that are specified in the BWRVIP report.

RAI B.1.23-1

The staff requests applicant to include the following statement (shown below) in the FSAR Section A.1.23, "Reactor Vessel Surveillance" of the LRA.

The applicant states that it will implement the BWRVIP integrated surveillance program (ISP) as specified in BWRVIP-116, "BWR Vessel Internals Project Integrated Surveillance Program Implementation for License Renewal" at the OCN unit. The staff is currently reviewing the BWRVIP-116 report, and if this report is not approved by the staff, the applicant must submit a plant-specific surveillance program for the OCN unit, two years prior to the commencement of the extended period of operation. The following commitment shall be included in the FSAR Section A.1.23, "Reactor Vessel Surveillance" of the LRA.

> **BWRVIP ISP as specified in BWRVIP-116, "BWR Vessel Internals Project Integrated Surveillance Program Implementation for License Renewal" and approved by the staff will be implemented, or if the ISP is not approved two years prior to the commencement of the extended period of operation, a plant-specific surveillance program for the OCN unit will be submitted.**

Response

Appendix A.1.23 and item number 23 of LRA Table A.5 will be updated to include the following:

> "BWRVIP ISP as specified in BWRVIP-116, "BWR Vessel Internals Project Integrated Surveillance Program Implementation for License Renewal" and approved by the staff will be implemented, or if the ISP is not approved two years prior to the commencement of the extended period of operation, a plant-specific surveillance program for Oyster Creek will be submitted."

RAI B.1.23-2

The staff requests the applicant to include the following statement (shown below) in the FSAR Section A.1.23, "Reactor Vessel Surveillance" of the LRA.

10 CFR Part 50, Appendix H, requires that an integrated surveillance program (ISP) used as a basis for a licensee implemented reactor vessel surveillance program be reviewed and approved by the NRC staff. The ISP to be used by the applicant is a program that was developed by the BWRVIP. The applicant will apply the BWRVIP ISP as the method by which the OCN unit will comply with the requirements of 10 CFR Part 50, Appendix H.

The BWRVIP ISP *identifies capsules that must be tested to monitor neutron radiation* embrittlement for all licensees participating in the ISP and identifies capsules that need not be tested (standby capsules). Tables 2-3 and 2-4 of the BWRVIP-116 report indicate that the capsules from OCN unit are not tested. These untested capsules were originally part of the applicant's plant-specific surveillance program and have received significant amounts of neutron radiation. The following commitment shall be included in the FSAR Section A.1.23, "Reactor Vessel Surveillance" of the LRA.

> **If the OCN *standby capsule is removed from* the RPV without the intent to test it, the capsule will be stored in manner, which maintains it in a condition, which would permit its future use, including during the period of extended operation, if necessary.**

<u>Response</u>

Appendix A.1.23 and item number 23 of LRA Table A.5 will be updated to include the following:

> "If the Oyster Creek standby capsule is removed from the RPV without the intent to test it, the capsule will be stored in manner which maintains it in a condition which would permit its future use, including during the period of extended operation, if necessary."