February 21, 2008

EA-08-046

Mr. Charles G. Pardee
Chief Nuclear Officer and
Senior Vice President
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville IL 60555

SUBJECT: BYRON STATION, UNITS 1 AND 2 SPECIAL INSPECTION - DEGRADATION OF THE ESSENTIAL SERVICE WATER RISER PIPING TO THE COOLING TOWER BASIN 05000454/2007009(DRS) AND 05000455/2007009(DRS) AND PRELIMINARY WHITE FINDING

Dear Mr. Pardee:

On February 14, 2008, the U.S. Nuclear Regulatory Commission (NRC) completed a Special Inspection at your Byron Station, Units 1 and 2 to evaluate the facts and circumstances surrounding the degradation of the essential service water (SX) system riser piping at the cooling tower basin, and the subsequent dual Unit shutdown on October 19, 2007. The circumstances surrounding the SX riser pipe degradation were evaluated against the criteria in Management Directive 8.3, "NRC Incident Investigation Program," and Inspection Manual Chapter 0309, "Reactive Inspection Decision Basis for Reactors." Based on the probabilistic risk and deterministic criteria specified in Management Directive 8.3 and Inspection Procedure 71153, "Event Followup," a Special Inspection was initiated in accordance with Inspection Procedure 93812, "Special Inspection." The Special Inspection Team (SIT) examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The SIT reviewed selected procedures and records, observed activities, and interviewed personnel with focus on the areas described in the Special Inspection Charter of Attachment 4 of the enclosed inspection report. The inspection report documents the inspection results, which were discussed at the exit meeting on February 14, 2008, with Mr. Dave Hoots and other members of your staff. The determination that the special inspection would be conducted was made by the NRC on October 23, 2007, and the inspection started on October 23, 2007.

This report discusses a finding that preliminarily appears to have low to moderate safety significance. The finding is associated with two apparent violations of NRC requirements. As described in Section 4OA3.3, one apparent violation involves your staff's failure to take timely corrective actions after the identification of extensive corrosion on SX riser pipes. As described in Section 4OA3.4, the second apparent violation involves your staff's failure to verify the adequacy of the methodology and design inputs in calculations that supported your staff's decision to accept three degraded SX riser pipes for continued service. The performance deficiencies associated with this finding directly contributed to the length of time the degraded riser pipes remained in service. The degraded SX riser pipe condition was caused by external pitting and general corrosion due to a lack of protective coating. Because the degraded sections of SX piping have been replaced and your staff implemented adequate initial extent of condition reviews, an immediate safety hazard no longer exists. However, the SIT identified that your staff missed an opportunity to prevent/mitigate corrosion of the SX system riser pipes, missed opportunities for early detection of corrosion, and missed opportunities for more timely corrective action. An inappropriate threshold for identifying external corrosion and lack of a questioning attitude contributed to the delay in identification and correction of the essential service water riser pipe degradation. The SIT concluded that associated performance deficiencies were the result of deficiencies in the Inservice Inspection, Engineering, and Problem Identification and Resolution Programs.

The NRC determined that the degraded SX riser pipe condition represented an increase in the likelihood of pipe rupture that could result in a loss of essential service water initiating event. The existing Significance Determination Process (SDP) guidance for increasing initiating event frequencies due to an increased probability of pipe rupture is not adequate to provide a quantitative risk estimate as the basis for the significance of the finding. Therefore, the NRC used both qualitative and quantitative criteria to assess the finding. Considering the degree and extent of SX riser degradation, the period of time the degraded condition existed, and the potential plant safety impact of an SX riser pipe rupture, the NRC concluded that the finding was best characterized as having low to moderate safety significance (White). The enclosed inspection report provides detailed information about the Phase 3 SDP analysis and assumptions used.

In accordance with Inspection Manual Chapter 0609, we intend to complete our evaluation using the best available information and issue our final determination of safety significance within 90 days of this letter. The significance determination process encourages an open dialogue between the staff and the licensee; however, the dialogue should not impact the timeliness of the staff's final determination.

Before we make a final decision on this matter, we are providing you an opportunity to either: (1) present to the NRC your perspectives on the facts and assumptions, used by the NRC to arrive at the finding and its significance, at a Regulatory Conference or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within 30 days of receipt of this letter and we encourage you to submit any supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. If you decide to submit only a written response, such submittal should be sent to the NRC within 30 days of the receipt of this letter. If you decline to request a Regulatory Conference or submit a written response, your ability to appeal the final SDP determination can be affected, in that by not doing either you fail to meet the appeal requirements stated in the prerequisite and limitation sections of Attachment 2 of Inspection Manual Chapter 0609. Please contact Mr. David Hills at (630) 829-9733 within 10 business days of the date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision and you will be advised by separate correspondence of the results of our deliberations on this matter.

The finding is associated with two apparent violations of NRC requirements and is being considered for escalated enforcement action in accordance with the NRC's Enforcement Policy, which can be found on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html. Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for this finding at this time. In addition, please be advised that the number and characterization of apparent violations described in the enclosed inspection report may change as a result of further NRC review.

In addition, three (Green) findings were identified and were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as Non-Cited Violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy.

If you contest any finding or NCV in this report, you should provide a response within 30 days of the date of this letter, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector at the Byron Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/
Steven West, Director
Division of Reactor Safety

Docket Nos. 50-454; 50-455
License Nos. NPF-37; NPF-66

Enclosure: Inspection Report 05000454/2007009(DRS); 05000455/2007009(DRS)
w/Attachments:
1. Supplemental Information
2. Timeline of Events
3. Pictures of Degraded SX Components
4. Byron Special Inspection Charter
5. IMC 609 – Appendix M Table 4.1 (Preliminary)

See Attached Distribution

Letter to Charles G. Pardee from Steven West dated February 21, 2008.

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cc w/encl:
Site Vice President - Byron Station
Plant Manager - Byron Station
Regulatory Assurance Manager - Byron Station
Chief Operating Officer and Senior Vice President
Senior Vice President - Midwest Operations
Senior Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Director - Licensing and Regulatory Affairs
Manager Licensing - Braidwood, Byron, and LaSalle
Associate General Counsel
Document Control Desk - Licensing
Assistant Attorney General
Illinois Emergency Management Agency
J. Klinger, State Liaison Officer, State of Illinois
P. Schmidt, State Liaison Officer, State of Wisconsin
Chairman, Illinois Commerce Commission
B. Quigley, Byron Station

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-454; 50-455
License Nos:	NPF-37; NPF-66
Report No:	05000454/2007009 and 05000455/2007009
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	Byron, IL 61010
Dates:	October 23, 2007 through February 14, 2008
Inspectors:	M. Holmberg, Team Lead T. Bilik, Reactor Inspector V. Meghani, Reactor Inspector C. Moore, Operator Licensing Examiner J. McGhee, Reactor Engineer L. Kozak, Senior Reactor Analyst
Approved by:	D. Hills, Chief Engineering Branch 1 Division of Reactor Safety

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SUMMARY OF FINDINGS

IR 05000454/2007009(DRS) and 05000455/2007009(DRS); 10/23/2007 - 02/14/2008; Byron Station, Units 1 and 2; Special Inspection to evaluate the facts and circumstances surrounding the degradation of the essential service water riser piping to the cooling tower basin.

On October 19, 2007, during rust removal from the 0C essential service water riser pipe near valve 0SX163C, in preparation for pipe wall thickness measurements, a ½ inch diameter 10 gallon-per-minute leak occurred (Attachment 3, Picture No. 3). Because this section of pipe could not be isolated from other cells on the 0A essential service water cooling tower basin, the licensee declared the 0A tower of the ultimate heat sink inoperable, and shut down both Units due to entry into Technical Specification 3.7.9 (reference LER 2007-002-00). The riser pipe leak was caused by a loss of pipe wall thickness due to external corrosion induced by the wet environment surrounding the unprotected carbon steel pipe. The corrosion processes that caused this leak affected all eight similar locations on the essential service water riser pipes within vault enclosures and had occurred over many years. The NRC initiated a Special Inspection Team which consisted of Region III inspectors and a Region III Senior Reactor Analyst, with technical support from the Office of Nuclear Reactor Regulation staff. This team was chartered to evaluate the facts, circumstances, and licensee actions surrounding the degradation of the riser piping.

This report covers a 110 day period of Special Inspection by the team of NRC inspectors. A preliminary White finding associated with two apparent violations and three Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. <u>Inspector-Identified and Self-Revealed Findings</u>

Cornerstone: Initiating Events

- <u>Preliminary White</u>. The team identified an apparent violation of 10 CFR 50 Appendix B, Criterion XVI, “Corrective action,” associated with the licensee’s failure to take timely corrective actions after identification of the corroded essential service water system riser pipes. Specifically, the licensee failed to take timely actions to remove the external corrosion layer present on the riser pipes to support sufficient wall thickness measurements to assess the significance of the pipe wall loss. Consequently, the licensee operated the plant for an extended period of time with a substantial loss of pipe wall on the essential service water riser piping while corrosion proceeded to the point that a through-wall leak developed on the 0C essential service water riser pipe.

  The cause of this apparent violation was related to the Decision Making Component (Item H.1(b) of IMC 305) for the cross-cutting area of Human Performance, because the licensee failed to make conservative assumptions in decisions affecting the integrity of the essential service water riser piping. The presumption of pipe integrity was not based on sufficient information to be able to demonstrate that the proposed action/decision to leave these risers in service was safe. The licensee subsequently completed a plant shutdown and replaced the degraded portions of these essential service water system riser pipes.

The finding associated with this apparent violation was greater than minor because the degraded essential service water piping condition resulted in an increase in the likelihood of the loss of the essential service water system due to pipe failures, which directly affected the Initiating Events Cornerstone. It was also associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding associated with this apparent violation was assessed using a Phase 3 analysis in accordance with NRC Inspection Manual Chapter 0609 Appendix M, "Significance Determination Process Using Qualitative Criteria," and is preliminarily determined to have low to moderate safety significance (White). (Section 4OA3.3)

- Preliminary White. The team identified an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," associated with the licensee's failure to verify the adequacy of the methodology and design inputs used to support licensee decisions to accept the degraded 0B, 0E and 0H essential service water system riser pipes for continued service. Specifically, the licensee failed to evaluate for compressive loads (e.g., buckling), use the applicable Code allowable stress, apply Code equations which account for thermal loads, and failed to correctly apply equations for checking the pipe functional capability. Consequently, the licensee failed to establish adequate design margins for continued service of the 0E, 0H and 0B essential service water system riser which resulted in extended plant operation with degraded SX riser pipes.

  The cause of this apparent violation was related to the Resources Component (Item H.2(a) of IMC 305) for the cross-cutting area of Human Performance, because the licensee failed to maintain plant safety by maintenance of design margins. Specifically, these degraded riser pipes remained in-service without establishing adequate design margins in the engineering evaluations to justify continued service. The licensee subsequently completed a plant shutdown and replaced the degraded portions of these essential service water system riser pipes.

  The finding associated with this apparent violation was greater than minor because the degraded essential service water piping condition resulted in an increase in the likelihood of the loss of the essential service water system due to pipe failures, which directly affected the Initiating Events Cornerstone. It was also associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding associated with this apparent violation was assessed using a Phase 3 analysis in accordance with NRC Inspection Manual Chapter 0609 Appendix M, "Significance Determination Process Using Qualitative Criteria," and is preliminarily determined to have low to moderate safety significance (White). (Section 4OA3.4)

Cornerstone: Mitigating Systems

- Green. The team identified a finding of very low safety significance and a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," for the licensee's failure to follow Procedure LS-AA-115, "Operating Experience Procedure," and implement corrective actions in response to an industry service water piping corrosion event which caused a service water system failure at a foreign reactor plant. Consequently, the licensee failed to implement actions to fix existing procedural controls so that a similar service water system corrosion and failure event would be precluded at the Byron Station. The cause of this finding was related to the Decision Making Component (Item H.1(b) of IMC 305) for the cross-cutting area of Human Performance, because the licensee did not make conservative assumptions in decisions affecting the integrity of this SX piping. Specifically, the licensee's decision to not implement changes to station procedures and to not perform training for personnel on this service water operating experience event was not based on sufficient information to demonstrate that the decision was safe (e.g., would preclude a similar event from occurring at the Byron Station). The licensee entered this issue into the corrective action program.

  This finding was determined to be more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening" because the finding was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee's failure to implement corrective actions associated with the Byron programs for maintenance of the service water system adversely affects system reliability. The team evaluated the finding in accordance with IMC 0609.04, "Phase 1 – Initial Screening and Characterization of Findings." Under the Mitigating Systems Cornerstone Column of Table 4a, the team answered "No" to each of the screening questions, because the failure to incorporate corrective measures for this applicable operating experience event did not directly contribute to the delay in correcting the degraded SX riser pipe condition. Specifically, each of the degraded SX riser pipes had been identified and placed in the corrective action system by June of 2007, shortly after this operating experience evaluation was performed. Therefore, the finding screened as having very low safety significance. (Section 40A3.3)

- Green. The team identified a finding of very low safety significance and a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," for the licensee's failure to ensure that Revision 54 of the Technical Requirements Manual was appropriate to the circumstances. Revision 54 of the Technical Requirements Manual was not appropriate to the circumstances, because it allowed deviations from the Technical Requirement Manual requirements without following the procedure change process and 10 CFR 50.59 review process. The cause of this finding was related to the Decision Making Component (Item H.1(b) of IMC 305) for the cross-cutting area of Human Performance, because the licensee failed to make conservative assumptions in decisions affecting the procedure adherence for safety related systems. Specifically, the licensee's assumptions for implementing Revision 54 were not based on a comprehensive review of system alignments for all possible Technical Requirements Manual deviations, and thus did not demonstrate that the proposed deviations allowed would be safe. The licensee subsequently removed the option to deviate from the Technical Requirements Manual and entered this issue into the corrective action program.

This finding was determined to be more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," because the finding was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Absent NRC intervention, the licensee's procedure option could have allowed unsafe deviations from the Technical Requirements Manual or allowed actions which would have required prior NRC approval (e.g., license amendment). The team evaluated the finding in accordance with IMC 0609.04 "Phase 1 – Initial Screening and Characterization of Findings." Under the Mitigating Systems Cornerstone Column of Table 4a, the team answered "No" to each of the screening questions, because the NRC identified this deficient change prior to the licensee implementing any actions which adversely affected the structural integrity or operability of mitigating systems. Therefore, the finding screened as having very low safety significance. (Section 40A3.7)

- Green. The team identified a finding of very low safety significance and a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the licensee's failure to identify severely corroded bolts (condition adverse to quality) on the 0B SX basin suction supply isolation valve 0SX138B. The cause of this finding was related to the Corrective Action Program Component (Item P.1(a) of IMC 305) for the cross-cutting area of Problem Identification and Resolution, because the licensee staff failed to adopt an appropriate threshold for identifying issues. Specifically, the failure of the licensee VT-2 examiner to identify these degraded bolts was related to an excessively high threshold for problem identification. The licensee entered this issue into the corrective action program and replaced the bolts on the lower half of this valve which were subjected to the most severe corrosion.

  This finding was determined to be more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening" because the finding was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Absent NRC intervention, the inappropriate threshold for identification of bolt corrosion as a condition adverse to quality would have gone uncorrected. This condition, if uncorrected, could lead to undetected corrosion failures in carbon steel components, affecting the reliability or capability of mitigating systems. The team evaluated the finding in accordance with IMC 0609.04, "Phase 1 – Initial Screening and Characterization of Findings." Under the Mitigating Systems Cornerstone Column of Table 4a, the team answered "No" to each of the screening questions, because the corrosion of the 0SX138B valve bolts had not yet challenged structural integrity or operability of the system. Therefore, the finding screened as having very low safety significance (Section 40A3.9).

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

Background and Overview

The essential service water (SX) system rejects heat to the SX cooling tower, both on a normal and on an emergency basis. The tower and SX basin constitute the ultimate heat sink (UHS) for the SX system and consist of a common eight cell mechanical draft cooling tower with safety-related make up. There is an "A" train side of the tower and a "B" train side of the tower, and each side has one common return from the associated train from each Unit. The discharges from each SX loop in each Unit are separate but merge into two separate and redundant return lines for SX system return to the cooling tower basin. Near the tower, the buried 48 inch diameter common return line splits into four buried 24 inch diameter lines which return water to individual cells within the cooling tower. The buried portions of this 24 inch diameter SX pipe reach the above-ground elevations within an enclosed chamber (referred hereinafter as a vault). These vaults are constructed of concrete and removable steel plates which serve to protect SX piping components from tornado generated missiles. Within each of the eight vaults, the portion of 24 inch diameter SX riser pipe runs vertically up through the concrete floor and terminates at a flange which supports a discharge isolation valve. Although, the SX riser vaults are enclosed, rainwater can enter through the roof/door interface and wind driven spray from the SX cooling tower outfall can enter through sheet metal panels forming the backwalls of the riser vaults. The floor of each riser vault is sloped to allow water to flow into drain holes (typically two) at the corner of the vault floor. Water intrusion into these vaults has contacted the uncoated carbon steel riser pipe providing a semi-continuous wetted environment, which caused significant external corrosion and wastage around the pipe perimeter just above the concrete floor elevation (Attachment 3, Pictures No. 1 through No. 5). The corroded portion of each riser pipe extended vertically four to six inches in height between the concrete floor and the support flange for its associated motor operated discharge isolation valve. The nominal pipe wall was originally 0.375 inch thick for these eight degraded pipes which are described as 0A through 0H SX riser pipes within this report.

The circumstances surrounding the essential service water riser pipe degradation was evaluated against the criteria in Management Directive 8.3, "NRC Incident Investigation Program," and Inspection Manual Chapter 0309 “Reactive Inspection Decision Basis for Reactors.” Deterministic Criteria g and h of Management Directive 8.3 were met for this event. A conditional core damage probability (CCDP) estimate for a reactor transient was performed to represent the dual Unit plant shutdown. The essential service water system was determined to be available because the leak on the 0C SX riser was well within the capacity of the essential service water makeup system and as a result there was no actual loss of essential service water function. The CCDP estimate using the NRC’s Simplified Plant Analysis Risk model, Revision 3.31, was 2.6E-6. This estimate is within the range of a special inspection. This risk calculation did not consider the potential impact of the degradation of the essential service water system due to corrosion and pipe wall thinning. A quantitative risk estimate could not be estimated for this condition, but the excessive pipe wall thinning could contribute to an increase in the loss of SX initiating event frequency. Because the loss of SX event is generally a high consequence event and the pipe degradation was common across all SX risers, the qualitative risk insights also supported a special inspection. Therefore, based on the probabilistic risk and deterministic criteria specified in Management Directive 8.3 and Inspection Procedure 71153, "Event Followup," a Special Inspection was initiated in accordance with Inspection Procedure 93812, "Special Inspection." The special inspection focus areas included the nine charter items related to the degraded SX riser piping (Attachment 4 – Special Inspection Team Charter).

4. OTHER ACTIVITIES (OA)

4OA3 Special Inspection (93812)

.1 Establish a sequence of events regarding licensee identification and actions to address degradation of the SX riser piping.

a. Inspection Scope

The team reviewed control room logs, plant parameter recordings, historical inservice tests, corrective action documents, maintenance work order and work request history, and engineering design changes and conducted interviews to determine the relevant sequence of events associated with licensee activities for inspection or maintenance of the SX piping within the SX vaults.

b. Findings and Observations

Sequence of Events Timeline

A detailed timeline of the relevant sequence of events related to the SX system riser pipe corrosion is included as Attachment 2 to this Report.

.2 Monitor the licensee's efforts to determine the root cause of the SX riser piping degradation and evaluate acceptability of these efforts including the timeline for feeding back results into current evaluation and repair efforts.

a. Inspection Scope

The team performed an on-site review and assessment of the scope and composition of the licensee's Root Cause Team (RCT) and evaluated the licensee conclusions on the causes for the SX riser degradation. The team also documented the licensee's final root causes identified in the root cause investigation report, "Through Wall Pipe Leak on the 0C SX Riser Piping Upstream of 0SX163C."

b. Findings and Observations

Overall, the team concluded that the composition and staffing of the licensee's RCT and RCT Charter were appropriate to identify the root causes for the SX riser pipe degradation.

b.1 On-Site Review of Root Cause Activities

The licensee initially formed a seven member RCT to identify the cause of the leak which occurred at the 0C SX riser piping. As of October 26, 2007, the licensee's RCT identified 9 potential failure modes/causes. Of these, the cause for this leak preliminarily included three of these factors: external pitting, general corrosion, and a lack of a protective coating. Corrosion mechanisms considered by the RCT, but ruled out, included galvanic, chemical, microbiological-induced, and flow accelerated corrosion. The RCT also considered, but ruled out, the impact damage from a chipping hammer used to clean SX riser surfaces and flow assisted erosion. The NRC team concluded the licensee's preliminary physical causes were consistent with the observed condition of the 0C SX riser with consideration for materials, operating history and environment.

The team evaluated the licensee's RCT Charter (Revision 6) and staffing. The scope of the RCT Charter included performing a metallurgical failure analysis and review of the organizational and programmatic issues that led up to the 0C SX riser pipe leak. Specifically, the licensee's RCT evaluated the site use of operating experience and the Corrective Action Program as they related to SX pipe riser degradation. The licensee's RCT was led by an Operations Program Analyst. RCT staff members included; Senior Engineers, a Work Manager, a Regulatory Specialist and a Metallurgist. The NRC team considered the licensee's RCT member composition and experience appropriate to complete the RCT Charter.

The RCT implemented the licensee's quarantine procedure to control materials and components saved for further testing and/or analysis to support the root cause determination and to preserve the as-found conditions of the degraded SX system components. The licensee applied the quarantine controls to the removed sections of the degraded riser pipes and the degraded bolts removed from the 0SX138A(B) valves identified during the extent of condition reviews. The quarantined components were stored in a roped off area inside a locked building. The team observed nondestructive testing on removed SX riser pipe sections within this quarantine area, and noted this area was appropriately locked and/or controlled to ensure material was not inadvertently lost or damaged. The degraded section of the 0C SX riser pipe was subsequently sent off-site to a vendor facility for further testing. The vendor tests included X-ray and chemical analysis of corrosion deposits, chemical analysis of the pipe base material, micrometer thickness measurements, scanning electron microscope examination of the through-wall hole surface, and metallurgical sectioning. NRC inspectors reviewed the vendor testing methods and results for the 0C riser pipe section, at the vendor's facility, and no deficiencies were identified. Based on interviews with the licensee RCT lead, the controls established were sufficient to provide accurate and timely feedback for root cause analysis. The team did not identify any issues with the control of materials which would affect the accuracy of the root cause analysis or impact the SX riser pipe repairs.

In BYR-71886, "Evaluation of Corrosion of Byron SX Cooling Tower Risers," the licensee documented the detailed evaluation of corrosion on the carbon steel riser pipe effects including metallurgical and laboratory test results from the removed 0B, 0C and 0H SX riser pipe sections. In this document, the licensee characterized the cause of the SX riser pipe wastage as "long-term external exposure of the non-protected carbon steel pipe to misting air/water cooling tower environment. The exposure resulted in severe general corrosion and pitting by an oxygen corrosion mechanism. Carbon steels are highly susceptible to oxygen corrosion when exposed to air saturated water. The external corrosion products on the risers exhibited a layered appearance, which is typical for carbon steel materials that are exposed to misting air or intermittent wetting conditions." Also, "The external corrosion deposits on the 0C riser contained moderate levels of leachable chlorides (0.15 percent) and sulfates (0.01 percent), which is expected since the SX system cooling water is treated with zinc chloride inhibitors, sodium hypochlorite biocides, and sulfuric acid for pH control. Based on the qualitative evaluations of the corrosion products, there were increased concentrations of these anions in some of the corrosion products that were adjacent to the external surface of the 0C riser, which would tend to increase corrosion pitting. The segregation of these anions beneath the corrosion products suggests that an under deposit concentration cell corrosion mechanism contributed to the external corrosion." In BYR-71886, the licensee also concluded that internal pitting and microbiologically induced corrosion did not play a significant role in the SX riser pipe failure.

b.2 Licensee Root Cause Investigation Report Findings

On December 12, 2007, the licensee issued a 150 page final root cause investigation report, "Through Wall Pipe Leak on the 0C SX Riser Piping Upstream of 0SX163C." In this report, the licensee identified three root causes:

- "A technical root cause was identified as general and pitting corrosion caused by long-term exposure of the non-protected carbon steel pipe to the misting air/water cooling tower environment,"

- "A programmatic root cause was identified that found less than adequate procedure guidance related to trending, tracking, identification threshold, and follow-up action determination related to safety related external pipe corrosion," and

- "An organizational issue was identified where over reliance of informal mechanisms is used to declare equipment operability. The root cause of this issue was management failed to identify weaknesses that led to ineffective decision-making affecting issue prioritization and driving timely completion of corrective actions. These weaknesses existed within the non-destructive evaluation, design assumptions, operations, engineering, work control, Corrective Action Program and the Plant Health Committee."

The team concluded that the licensee's RCT had used appropriate processes and methods including failure modes and effects, use of an event and causal factor chart, and TapRooT® to conduct and identify causes for the SX riser degradation. The licensee assigned corrective and preventative actions for each of the root causes, but the team's review scope did not include evaluation of the adequacy of these proposed corrective actions.

.3 Evaluate the adequacy and effectiveness of licensee processes and implementation thereof to identify and address the SX riser piping degradation in a timely manner. Include evaluation of any licensee decisions and communication thereof coming out of the licensee's internal October 17, 2007, meeting.

a. Inspection Scope

The team reviewed the procedures and training provided to the licensee's VT-2 inspection staff and engineers for the past 5 years related to SX system inspection requirements to evaluate the effectiveness of these processes and programs for identification and correction of external corrosion. The team also conducted interviews with licensee VT-2 staff, engineers, maintenance staff, and operations staff to evaluate thresholds for identification of corrosion as a condition adverse to quality in the licensee's Corrective Action Program. The team reviewed applicable industry operating experience related to the SX system pipe integrity and licensee evaluations of this information. In addition, the team reviewed maintenance work packages and corrective action documents related to the SX pipe maintenance performed near the SX risers since 1997.

b. Findings and Observations

The team determined that licensee programs and processes did not provide sufficient focus on external corrosion to preclude the SX riser pipe degradation. Specifically, the licensee had an opportunity to prevent/mitigate corrosion of the SX system riser pipes, as well as numerous opportunities for earlier detection of corrosion and numerous opportunities for more timely corrective action. A high threshold for identifying external corrosion, and/or lack of a questioning attitude contributed to the delay in identification and correction of the essential service water riser pipe wastage. The team concluded that associated performance deficiencies were the result of deficiencies in the Inservice Inspection, Engineering, and Problem Identification and Resolution Programs.

b.1 Missed Early Opportunity to Prevent SX Riser Pipe Corrosion

In 1993, the licensee established an SX Riser Valve Task Force to evaluate the pipe conditions for the SX basins and repair options. This task force developed repair plans at a May 1993 meeting, which included initiation of work requests to clean and recoat the SX riser pipe between the concrete floor and flange to protect these pipes from further corrosion. In 1995, a member of this task force cancelled these work requests, based on the mistaken belief that this section of pipe would be replaced during future modifications. However, the scope of the 1997 SX system modification that replaced the carbon steel SX pipe with stainless steel pipe did not include the SX pipe risers upstream of the 0SX163 valves. The team interviewed the licensee staff member involved in initiation and cancellation of the work requests to clean and recoat the SX riser pipe and licensee staff involved with the 1997 SX pipe replacement modification, but no further information was obtained. If replacement or protective coating of the SX riser pipe had been included within the scope of the 1997 modification, the SX riser pipe degradation would not have occurred or it would have been significantly mitigated. In this case, the licensee's internal communication processes failed and consequently, the licensee missed an opportunity to prevent or mitigate the external corrosion that severely degraded the SX riser pipes.

b.2 Missed Early Opportunities for Prior Detection of SX Riser Pipe Corrosion

In March and April of 1990, a licensee internal memorandum and contractor report identified that substantive corrosion was present on the SX cooling tower carbon steel distribution piping. Based upon the licensee contractor's estimated corrosion rates of up to 5-10 mils per year for carbon steel SX piping, and the corroded conditions observed on the 0F SX riser pipe from a picture taken in 2003, the team concluded that the external corrosion process affecting the riser pipes had been active for more than a decade. From 1997 through 2004, the licensee missed numerous early opportunities (discussed below) to identify and mitigate the external corrosion on the riser pipes. The team concluded that the licensee engineering, maintenance, and operations staff had an inappropriate threshold for identification of corrosion that contributed to the delay in identification of the degraded SX riser piping.

The team could not explicitly determine the degree of pipe corrosion and wastage present during these early opportunities for the licensee to have identified the degraded SX riser pipes. Therefore, the program deficiencies which contributed to these missed opportunities as discussed below, did not constitute violations of NRC requirements. However, the team did identify more recent licensee performance deficiencies associated with these degraded SX riser pipes that were considered violations of NRC requirements (see Report Sections 4OA3.3, 4OA3.4, 4OA3.7 and 4OA3.9) and which reflect these same deficiencies.

VT-2 Examinations

As required by 10 CFR 50.55a, the licensee had established an Inservice Inspection program in accordance with the American Society of Mechanical Engineers (ASME) Code Section XI. As part of the Inservice Inspection Program, the licensee implemented periodic VT-2 visual examinations of the safety-related Code piping systems, including the SX system. The licensee performed three or more VT-2 visual examinations for each of the degraded riser pipes from 1997 through 2004. During these VT-2 examinations, the licensee inspection staff directly observed the riser pipe surface to look for evidence of leakage. No evidence of leakage was recorded, and the corroded condition of the riser pipes was never documented in the corrective action system (prior to 2006). To determine the reason for this oversight, the team interviewed VT-2 inspection staff and training personnel, and reviewed licensee procedures used to complete VT-2 examinations.

The training program provided to the licensee's VT-2 inspection staff for the past five years included written and practical training modules focused on identification of leakage. This training included a review of corrosion mechanisms and industry events such as the corrosion induced wastage identified on the Davis-Besse reactor vessel head. The training corrosion module guidance included the statement, "Corrosion attack can range from uniform corrosion generally over the surface, to a very localized pitting. Pitting corrosion is discussed in another section; however, during visual examination, the nature, extent, and depth of any non-uniform corrosion should be documented." The course material and VT-2 inspection procedure emphasized inspection of bolts subject to corrosion induced by leakage, but did not include pictures of corroded piping or bolts. While not required by the ASME Code, the licensee's VT-2 Procedure ER-AA-335-15 required the VT-2 inspector to look for areas of general corrosion and evaluate and record the depth of corrosion where it affected pressure retaining components. However, no explicit procedural guidance was provided for steps needed to evaluate external corrosion to determine if pressure boundary wastage had occurred. Further, this procedure prohibited the VT-2 inspector from disturbing the surface under examination.

The team concluded that the VT-2 training and procedural guidance was not sufficient to ensure early identification and assessment of pipe degradation from external corrosion. Additionally, the team identified a lack of questioning attitude, and an inappropriate threshold for identification of external pipe corrosion by the VT-2 inspectors which contributed to the delay in identification of the SX riser pipe degradation. The inappropriate threshold for identification of external corrosion was also demonstrated in the licensee's recent failure to identify corroded bolting at the 0SX138B valve (Report section 4OA3.9). The licensee documented these concerns regarding the VT-2 inspection portion of its Inservice Inspection Program in the corrective action system (IR 00696303).

Engineering Inspections

As part of its Engineering Program, the licensee expects system/plant engineers to conduct periodic walkdowns of plant systems. On May 14, 2004, licensee staff from the Plant Engineering Department conducted a walkdown inspection of the SX system components within the 0G SX riser vault and identified a buildup of corrosion products on the valve flange bolting and nuts fastened to the 0G SX riser flange. Although these corroded fasteners attached directly to the flange above the degraded riser pipe, the engineering staff did not identify or evaluate the corroded condition of the 0G SX riser pipe. The team also identified other examples where engineering, maintenance and operations staff performed work activities, in and around the degraded riser pipes, without documenting the corroded condition of the riser pipes in the corrective action system. To determine the reasons for this oversight, the team interviewed engineering staff and training personnel, and reviewed the procedures used by engineers to for conduct system walkdowns.

The team reviewed the training provided to the license engineering staff for the past five years. This training included initial and continuous training modules which discussed corrosion mechanisms. The continuous training provided to system/plant engineers discussed visual examination as a means to identify corrosion induced wastage. This training also described various methods to measure pipe wall thickness. However, this training did not include pictures of externally corroded components, nor did it provide guidance on when (e.g., threshold) or how to evaluate external corrosion induced wastage. The walkdown guidance provided for system engineers with respect to corrosion was contained in Attachment 4 of ER-AA-2030, “System Walkdown Standards.” Attachment 4 provided the licensee staff with a checklist of general material condition issues that included “Preservation (rust, corrosion…).” However, no explicit procedural guidance was provided to discuss methods or tools needed to assess this checklist item. The licensee’s SX system engineer also indicated that based on the training provided, insufficient guidance or expectations existed to ensure that component integrity assessments would occur for components affected by external corrosion.

The team concluded that the system/plant engineering training and walkdown procedural guidance was not sufficient to ensure early identification and assessment of pipe degradation from external corrosion. Additionally, the team concluded that the engineering staff’s lack of a questioning attitude, and an inappropriate threshold for identifying external corrosion contributed to the delay in identification of SX riser pipe degradation. The licensee documented these Engineering Program deficiencies in the corrective action system (IR 00696303).

Routine Maintenance Activities

Between 1997 and 2004, the licensee staff performed numerous routine corrective and preventative maintenance activities in and around the degraded SX riser pipes (Attachment 2 – Timeline of Events). For example, the licensee routinely performed maintenance and testing of the 0SX163 valves directly above the degraded SX riser pipe and performed corrective maintenance on corroded electrical conduits located at the concrete floor of the SX vaults approximately one foot from the degraded riser pipe.

During these activities, licensee maintenance and operations staff would have had opportunities to view the corroded riser pipe condition, and yet failed to recognize the potential problem. The team concluded that lack of a questioning attitude, and a high threshold for identifying external corrosion contributed to the delay in identification of SX riser pipe degradation.

Operating Experience Procedure Not Followed for Service Water Corrosion Event

Introduction: The team identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," for the licensee's failure to follow Procedure LS-AA-115, "Operating Experience Procedure," and implement corrective actions in response to an industry service water piping corrosion event which caused a service water system failure at a foreign reactor plant.

Description: On November 8, 2007, the team identified that the licensee failed to follow Procedure LS-AA-115, "Operating Experience Procedure," and implement corrective actions in response to an industry service water piping corrosion event, which caused a service water system failure at a foreign reactor plant. Consequently, the licensee failed to implement actions to fix existing procedural controls so that a similar SX corrosion induced failure event would be precluded at the Byron Station.

In November of 2006, the licensee received information which discussed a failure at a metal access port for a service water system in a foreign plant. This industry experience was also discussed in NRC Information Notice (IN) 2007-06, "Potential Common Cause Vulnerabilities in Essential Service Water Systems," issued on February 9, 2007. NRC IN 2007-06 identified events at foreign operating reactors where external corrosion of piping located in vaults caused a catastrophic loss of one train of the service water system. One event involved a service water system manhole pipe that experienced a circumferential break which caused a loss of one train of the service water system. At this foreign plant, the service water pipes were buried with below grade manholes to allow for inspection and maintenance. The failed service water manhole pipe was exposed to external surface water which corroded the carbon steel manhole at the pipe neck. An extent-of-condition review identified similar corrosion at two other service water pipe manhole necks that required significant repair work. The manhole pipe neck break was caused by external corrosion due to improper installation of an external pipe coating. This event was of concern for plant safety, because it could have led to a common cause failure of the service water system, which provides cooling for most safety-related loads.

On March 29, 2007, the licensee staff reviewed the foreign plant event discussed above for applicability to the Byron Station and determined that this event was applicable to the Bryon Station SX system (specifically to the SX pipe located within vaults). The licensee reviewed and dispositioned this operating experience event in accordance with Procedure LS-AA-115, "Operating Experience Procedure." Based on this review, the licensee did not identify any further actions needed for the Byron Station. Specifically, the licensee concluded that implementation of the Raw Water Program and periodic visual examinations were adequate to address this issue. However, the NRC team identified that the Raw Water Program provided ultrasonic methods for detection of corrosion on buried pipe, but lacked a defined visual examination program or other methods which would be effective for detection of external corrosion in non-buried carbon steel piping systems. Further, the team concluded that the periodic VT-2 visual examinations were also not effective for detection of external corrosion in non-buried piping systems.

The team reviewed the specific resolution of this issue documented by the licensee staff in Attachment 1 of Procedure LS-AA-115. In Attachment 1, the licensee answered “no” to Question 6 which asked if existing procedure controls were effective in precluding the problems described in the operating experience document. Therefore, the licensee’s operating experience evaluator had concluded that existing procedural controls were not effective in precluding the problem(s) described in the operating experience document. With this answer, the licensee should have followed Step 4.1.2.6.c of Procedure LS-AA-115 and implemented actions to correct the applicable site procedures. However, the licensee failed to identify the procedures affected and implement actions to fix site procedures so that a similar SX event would not occur at the Byron Station. Additionally, the licensee answered “No” to Attachment 1, Question 7 which asked if training was required for this event. In this case, the team concluded that training on this event would have been appropriate to sensitize licensee staff to this type of corrosion induced failure and where it could affect piping components at the Byron Station (e.g., unprotected carbon steel pipe in areas subject to water intrusion).

Analysis: The team determined that failure to follow operating experience Procedure LS-AA-115 in response to applicable industry service water event was a performance deficiency that warranted a significance evaluation.

The team determined the finding was more than minor in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” because; the finding was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee’s failure to implement corrective actions associated with the Byron programs for maintenance of the SX system adversely affects system reliability.

The team evaluated the finding in accordance with IMC 0609.04, “Phase 1 – Initial Screening and Characterization of Findings.” Under the Mitigating Systems Cornerstone Column of Table 4a, the team answered “No” to each of the screening questions, because the failure to incorporate corrective measures for this applicable operating experience event did not directly contribute to the delay in correcting the degraded SX riser pipe condition. Specifically, each of the degraded SX riser pipes had been identified and placed in the corrective action system by June of 2007, shortly after this operating experience evaluation was performed. Therefore, the finding screened as having very low safety significance (Green).

The cause of this finding was related to the Decision Making Component (Item H.1(b) of Inspection Manual Chapter (IMC) 305) for the cross-cutting area of Human Performance, because the licensee did not make conservative assumptions in decisions affecting the integrity of the SX system piping. Specifically, the licensee’s decision to not implement changes to procedures and to not perform training for personnel on this service water operating experience event was not based on sufficient information, to be able to demonstrate that the proposed decision was safe (e.g., would preclude a similar event from occurring at the Byron Station).

Enforcement: During an NRC inspection conducted between October 23, 2007, and February 14, 2008, a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings" was identified.

Title 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances, and shall be accomplished in accordance with these instructions, procedures, or drawings.

Step 4.1.2.6.C of Procedure LS-AA-115, "Operating Experience Procedure," required "Formulate proposed actions necessary to appropriately address all affected items using the guidelines in Attachment 1, OPEX Reviewer's Guidelines."

Contrary to the above, on March 29, 2007, during the review of an operating experience event involving a corrosion induced failure of the SX system, the licensee failed to formulate proposed actions necessary to appropriately address the item identified in response to Question 6 of Attachment 1 of Procedure LS-AA-115. Specifically, the licensee concluded that existing procedural controls were not effective in precluding the problem(s) described in the operating experience document and failed to formulate actions to identify and address the non effective procedural controls. Because this finding was of very low safety significance and because the finding was entered into the licensee's corrective action program (reference Action Request (AR) 00696519), this violation is being treated as a non-cited violation (NCV 0500454/2007009-01; NCV 0500455/2007009-01) consistent with Section VI.A of the NRC Enforcement Policy.

b.3 Failure to Implement Timely Corrective Actions for Degraded SX Riser Piping

Introduction: The team identified an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the licensee's failure to take timely corrective actions after identification of the corroded SX system riser pipes.

Description: On November 7, 2007, the team identified that the licensee failed to take timely actions to correct the degraded SX riser pipe after identification of these conditions in the corrective action system. The team identified the following timeline of events related to corrective action timeliness for each of the SX riser pipes.

In May of 2006, and then again on March 5, 2007, the licensee identified corrosion on the 0C SX system riser pipe. Specifically, in AR 00599643, the licensee documented "There is corrosion product flaking off from the pipe. Last year no loose flaking was observed lying around the pipe." The licensee also retained a photograph dated May 23, 2006, which showed rust on the 0C SX riser flange. The licensee generated a work request to clean this pipe, but this work was not accomplished prior to the dual Unit plant shutdown. On October 19, 2007, the 0C SX riser pipe developed a through-wall leak (Attachment 3, Picture No. 3) and the riser pipe was later found to contain three additional through-wall holes plugged with corrosion products.

On October 16, 2006, the licensee identified corrosion on the 0D SX riser pipe. Specifically, in AR 00544803, the licensee documented "The 0SX163D riser valve piping between the concrete floor and the valve (about 4 inches in length) is corroding…" The licensee generated a work request to clean this SX riser pipe, but this work was not accomplished prior to the dual Unit shutdown. After shutdown, the team observed extensive corrosion present on the 0D riser pipe (Attachment 3, Picture No. 4).

On November 30, 2006, the licensee identified corrosion on the 0B SX system riser pipe. Specifically, in AR 00563914 and AR 00563907, the licensee documented that “In the riser valve vault the 4 inches of carbon steel piping between the concrete floor and valve 0SX163B is showing signs of corrosion and needs to be cleaned and coated.” The corroded condition of this riser pipe, was also captured in a photograph (Attachment 3, Picture No. 2) taken by the licensee in November of 2006. Then again on May 31, 2007, the licensee identified corrosion on the 0B SX riser as documented in AR 00630679. The licensee generated work requests to clean and coat this SX riser pipe, but this work was not accomplished prior to the dual Unit shutdown. After shutdown, the team observed extensive corrosion present on the 0B SX riser pipe and the pipe had developed a through-wall hole plugged with corrosion products.

On May 17, 2007, the licensee identified corrosion on the 0A SX riser pipe. Specifically, in AR 00630679, the licensee documented that “approximately 4 inches of exposed carbon steel pipe upstream of riser valve 0SX163A has had the protective coating degrade to the point that there is some flaking of the carbon steel pipe.” Then again on June 5, 2007, the licensee identified in AR 00637335 “rusting/flecking of piping below the riser valve 0SX163A.” The licensee generated a work request to clean this SX riser pipe, but this work was not accomplished prior to the dual Unit shutdown. After shutdown, the team observed extensive corrosion present on the 0A SX riser pipe (Attachment 3, Picture No. 1).

On May 17, 2007, the licensee identified corrosion on all of the SX system riser pipes. Specifically, in AR 00630679, the licensee documented that “approximately 4” of exposed carbon steel pipe upstream of riser valve 0SX163A has had the protective coating degrade to the point that there is some flaking of the carbon steel pipe” and, “this condition exists at all of the riser valves.” Then again on June 5, 2007, the licensee identified corrosion on all of the SX system riser pipes. Specifically, in AR 00637335, the licensee documented “rusting/flecking of piping below the riser valve 0SX163A. This kind of degradation is found in all other cells also.” The team noted that this description would include corrosion of the 0F and 0G SX riser pipes. The team also reviewed a photograph that included the 0F SX riser pipe taken by the licensee in 2003. In this photograph, the team identified flake type corrosion deposits on the concrete floor surrounding the riser pipe, which appeared to have fallen off the surface of the riser pipe. The licensee generated a work requests to clean and recoat the SX riser pipes, but this work was not accomplished prior to the dual Unit shutdown. After shutdown, the team observed extensive corrosion present on the 0F and 0G SX riser pipes.

On June 4, 2007, the licensee identified corrosion on the 0H system riser pipe. Specifically, in AR 00636745, the licensee documented that “approximately 4 inches of exposed carbon steel pipe upstream from riser valve 0SX163H has had the protective coating degrade, exposing the carbon steel pipe.” The licensee generated a work requests to clean this SX riser pipe, but this work was not accomplished prior to the dual Unit shutdown. After shutdown, the team observed extensive corrosion present on the 0H SX riser pipe.

On June 14, 2007, the licensee identified corrosion (Attachment 3, Picture No. 5) on the 0E SX system riser pipe and performed UT measurements of pipe wall-thickness at two points approximately 1 inch in diameter (reference UT report 2007-005 and AR 00640363). The licensee recorded wall thickness measured at these two points (0.122 inch and 0.124 inch) that was substantially below the nominal pipe wall thickness of 0.375 inch. The licensee discussed the degraded 0E SX riser pipe at the Plant Health Committee (PHC) meeting on June 25, 2007, and the PHC recommended repair of the degraded SX riser pipes, but no repair work was accomplished prior to the dual Unit shutdown. After shutdown, the team observed extensive corrosion present on the 0E SX riser pipe.

The team concluded that for each of the eight SX riser pipes subject to external corrosion, the licensee failed to take timely corrective actions to determine the extent and significance of the pipe wall loss. Specifically, the licensee failed to take timely actions to remove the external corrosion layer present on the riser pipes to support sufficient wall thickness measurements to assess the significance of the pipe wall loss. Consequently, the licensee operated the plant for an extended period of time with a substantial loss of pipe wall on the SX riser piping while corrosion proceeded to the point that a through-wall leak developed on the 0C SX riser pipe. On October 21, 2007, the licensee completed a plant shutdown and initiated repairs to the degraded portions of the SX riser pipes.

Analysis: The team determined that failure to take timely corrective actions for the eight degraded SX riser pipes was a performance deficiency that warranted a significance evaluation. The team further determined that the issue was within the licensee's ability to foresee and correct and in fact, could have been prevented as discussed in report Section 4OA3.3.

The original pipe design Code maintained margins to ensure the pipe material remains well within elastic material property ranges. The licensee analysis performed in support of past operability (Section 4OA3.8) demonstrated that elastic margins would not be maintained in the degraded pipe areas, and instead would be subject to plastic deformation within the pipe material limits. In particular, for SX riser pipes 0A, 0B, 0C, 0D, and 0E, with multiple areas of pipe wall thickness below 0.1 inch and/or the presence of through-wall holes, local areas of the pipe were subject to plastic deformation. Because elastic material behavior under normal and accident loads was no longer assured, the team concluded, based on engineering judgment, that the SX riser pipes left in service had an increased probability of rupture.

The team determined the finding associated with this apparent violation was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," because the degraded SX piping condition resulted in an increase in the likelihood of the loss of the SX system due to pipe failures, which directly affected the Initiating Events Cornerstone. It was also associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee's lack of timely actions to determine the extent and significance of pipe wall loss resulted in failure of the 0C SX riser pipe and resulted in extended plant operation with an increased risk of riser pipe failures. The increased risk of riser pipe failures adversely affected the SX system reliability because a riser pipe failure could cause an unrecoverable loss or flow diversion from the SX basin water supply (e.g., UHS). If this flow diversion was greater than SX makeup capacity, a loss of the SX system would occur causing a loss of several other risk significant systems and components (e.g., emergency diesel generators, reactor coolant pumps, residual heat removal cooling heat exchangers, etc.).

The finding associated with this apparent violation was evaluated in accordance with IMC 0609.04 "Phase 1 – Initial Screening and Characterization of Findings." In applying the SDP Phase 1 Screening Worksheet, the degraded SX risers were treated as a condition which could increase the likelihood of a loss of SX event. A loss of SX affected the Transient Initiator contributor under the Initiating Events Cornerstone and also affected the Secondary and Long-Term heat removal categories under the Mitigating Systems Cornerstone. In accordance with IMC 0609.04 "Phase 1 – Initial Screening and Characterization of Findings," if the finding affects multiple reactor cornerstones, the finding should be assigned the cornerstone that best reflects the dominant risk of the finding. The degraded service water condition directly contributed to the increased probability for a loss of service water initiating event, which represented the dominant risk contributor for this finding. Therefore, this finding was assigned to the Initiating Events Cornerstone. Since this finding is related to pipe degradation, the potential for pipe rupture, and subsequent loss of inventory, the SDP Phase 2 guidance was not applicable. Specifically, no SDP guidance exists to estimate the increase in rupture frequency for the degraded SX riser piping and further, the risk significance of the finding is highly dependent on assumptions regarding the increased potential for pipe rupture and the degree of leakage given rupture. Therefore, in accordance with Item 6 of Table 3b of IMC 06.09.04, where existing SDP guidance is not adequate to provide a reasonable estimate of the finding significance, the risk evaluation is required to be performed in accordance with IMC 0609, Appendix M, "Significance Determination Process Using Qualitative Criteria." The NRC performed a Phase 3 significance evaluation using IMC 609 Appendix M, which is discussed in Report Section 4OA3.8. As a result of this analysis, the finding associated with this apparent violation was characterized as having low to moderate safety significance (preliminary White).

The cause of this apparent violation was related to the Decision Making Component (Item H.1(b) of IMC 305) for the cross-cutting area of Human Performance, because the licensee failed to make conservative assumptions in decisions affecting the integrity of the SX riser piping. Specifically, the licensee's presumption of pipe integrity was not based on sufficient information to be able to demonstrate that the proposed action/decision to leave these risers in service was safe.

Enforcement: During an NRC inspection conducted between October 23, 2007, and February 14, 2008, seven examples of an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," were identified.

10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected.

Contrary to the above,

- From May 17, 2007, to October 20, 2007, the licensee failed to assure that a condition adverse to quality was promptly corrected. Specifically, on May 17, 2007, the licensee identified in AR 00630679 that there was significant corrosion of the 0A SX riser pipe. However, as of October 20, 2007, no corrective actions had been taken to correct this condition.

- From November 30, 2006, to October 20, 2007, the licensee failed to assure that a condition adverse to quality was promptly corrected. Specifically, on November 30, 2006, the licensee identified in AR 00563914 and AR 00563907 that there was significant corrosion of the 0B SX riser pipe. However, as of October 20, 2007, no corrective actions had been taken to correct this condition.

- From May 2006, to October 20, 2007, the licensee failed to assure that a condition adverse to quality was promptly corrected. Specifically, on March 5, 2007, the licensee identified in AR 00599643 that there was significant corrosion of the 0C SX riser pipe and the corroded condition had degraded from the time of a May 2006 inspection. However, as of October 20, 2007, no corrective actions had been taken to correct this condition.

- From October 16, 2006, to October 20, 2007, the licensee failed to assure that a condition adverse to quality was promptly corrected. Specifically, on October 16, 2006, the licensee identified in AR 00544803 that there was significant corrosion of the 0D SX riser pipe. However, as of October 20, 2007, no corrective actions had been taken to correct this condition.

- From June 14, 2007, to October 20, 2007, the licensee failed to assure that a condition adverse to quality was promptly corrected. Specifically, on June 14, 2007, the licensee identified in UT report 2007-005 and AR 00640363 that there was significant corrosion of the 0E SX riser pipe. However, as of October 20, 2007, no corrective actions had been taken to correct this condition.

- From May 17, 2007, to October 20, 2007, the licensee failed to assure that a condition adverse to quality was promptly corrected. Specifically, on May 17, 2007, the licensee identified in AR 00630679 and again on June 5, 2007, in AR 00637335, that there was significant corrosion on all SX riser pipes (including the 0F and 0G SX riser pipes). However, as of October 20, 2007, no corrective actions had been taken to correct this condition.

- From June 4, 2007, to October 20, 2007, the licensee failed to assure that a condition adverse to quality was promptly corrected. Specifically, on June 4, 2007, the licensee identified in AR 00636745 that there was significant corrosion of the 0H SX riser pipe. However, as of October 20, 2007, no corrective actions had been taken to correct this condition.

Because the licensee replaced the degraded sections of SX piping and implemented adequate initial extent of condition reviews, an immediate safety hazard no longer exists. The licensee entered this finding into the corrective action program (AR 00693484 and AR 00696006). This is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Actions,” pending completion of a final significance determination (AV 05000454/2007009-02(DRS); AV 05000455/2007009-02(DRS)).

b.4 October 17, 2007 Risk Meeting

The team evaluated licensee decisions and the timeliness of the licensee's corrective actions following identification of the 0B SX riser pipe wall thinning. The licensee held an internal risk meeting on Wednesday October 17, 2007, to discuss near term planned maintenance work activities, including ongoing corrective actions related to identification of wall thinning on the 0B SX riser piping. During this meeting, a member of the licensee staff stated that the station should stop doing additional UT on the SX riser piping. On October 18, 2007, the licensee issued a "Byron News Flash" to address any potential miscommunication related to this discussion. In this news flash, the licensee stated "Regrettably it was stated at the risk meeting that the station should stop performing additional UT on these pipes. After further discussion, a decision was made to continue with the inspections but delay Thursday's inspection until a team could be formed to discuss a "go forward" plan. The intent was never to stop the inspections…" The licensee also delayed continuing with UT inspections until Friday, October 19, 2007, to allow for severe weather to move out of the area. This delay was necessary because the licensee's policy is to not remove the missile shield barriers from the SX riser vaults whenever weather conditions create the possibility of wind driven missile damage to SX system components within the vaults. The team concluded that there were no unnecessary delays imposed in continuing with UT examinations to measure wall thickness on SX riser piping following the October 17, 2007, risk meeting.

.4 Evaluate the adequacy of the licensee's past operability decisions for the essential service water riser piping degradation.

a. Inspection Scope

The team developed a timeline of riser pipe wall thickness measurements and operability decisions (e.g., acceptance for continued service) and the calculations used to support the licensee's decisions to accept the degraded 0B, 0E and 0H SX riser pipes for continued service. Specifically, the team reviewed these calculations to determine if the licensee had established applicable design margins and an appropriate basis to demonstrate that these degraded riser pipes were acceptable for continued service.

b. Findings and Observations

b.1 Timeline of Riser Pipe Wall Thickness Measurements and Operability Decisions

The original nominal pipe wall thickness of these SX riser pipes was 0.375 inch thick. From June through October of 2007, the licensee measured the pipe wall thickness for three of the eight SX riser pipes (0E, 0H and 0B) and identified areas of pipe wall loss. To accept these three SX risers for continued service, the licensee performed calculations to determine the minimum acceptable wall thickness as identified in the timeline below.

On June 14, 2007, the licensee documented in UT report No. 2007-382 and AR 00640363, the 0E SX riser pipe wall thickness measured at two areas on the pipe perimeter 180 degrees apart. The minimum pipe wall thickness recorded at these two locations was 0.124 inch and 0.122 inch, respectively.

On July 11, 2007, the licensee documented in AR 00640363-02, the application of EC 366395, "Nonconformance Evaluation for Line 0SX97AE-24 Near Valve 0SX163E," to the 0E SX riser pipe wall thickness and accepted this riser pipe for "use-as-is." In EC 366395, the licensee established a minimum design pipe wall thickness of 0.121 inch applicable to the 24 inch diameter SX riser pipes.

On October 10, 2007, the licensee documented in UT report No. 2007-474 and AR 00682786, the 0H SX riser pipe wall thickness measured at 3 areas around the pipe perimeter. The minimum pipe wall thicknesses were 0.085 inch, and 0.154 inch, and 0.150 inch.

On October 12, 2007, the licensee completed Operability Evaluation 07-009 and EC 367754 for the 0H SX riser pipe. The licensee concluded that the piping was operable based on a new minimum acceptable wall thickness of 0.06 inch, and predicted a remaining life of 2.1 years for this pipe section.

On October 17, 2007, the licensee documented in UT report No. 2007-478 and AR 00685955, the 0B riser pipe wall thickness measured at 10 areas around the pipe perimeter. The pipe wall thickness measured was below 0.1 inch at each of these locations. The lowest reading recorded was 0.047 inch.

On October 17, 2007, the licensee documented and accepted the 0B SX riser pipe wall thickness measurements in AR 00685955, "Minimum Wall on SX Riser Piping, 0SX97AB-24." Specifically, the licensee applied equation 9D of Appendix F from EC 367754 to determine a new minimum allowable wall thickness of 0.03 inch.

As discussed in Section 4OA3.4. b.2, the licensee engineering staff made substantive errors in the calculations that supported operability evaluations for these degraded SX riser pipes. Based on the timeline above, the team noted that the licensee staff had three separate opportunities to have identified these errors during review of calculations and operability evaluations and failed to do so.

b.2 Inadequate Design Margins for Continued Operation of SX Riser Pipes

Introduction: The team identified an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for failure to verify the adequacy of the methodology and design inputs used to support licensee decisions to accept the degraded 0B, 0E and 0H SX riser pipes for continued service.

Description: On November 8, 2007, the team identified that the licensee had not considered appropriate loads and, therefore, had not maintained appropriate design margins to support decisions to accept the degraded 0B, 0E and 0H SX riser pipes for continued service. Specifically, the licensee failed to evaluate for compressive loads (e.g. buckling), to use the applicable Code allowable stress, to apply Code equations which account for thermal loads, and to correctly apply equations for checking the pipe functional capability.

Within each of the eight SX riser vaults, the portion of 24 inch diameter SX riser pipe coming vertically up through the concrete floor terminates at a flange which supports a discharge isolation valve. This segment of SX pipe continues on through a second concrete slab. With this highly constrained configuration (i.e., SX pipe segment fixed/anchored at both ends), an increase in system operating temperature will cause the metal pipe to expand and move, creating axial compression as well as a bending moment about the fixed ends (i.e., where the pipe penetrates the concrete slabs) of this pipe section. This thermally induced bending moment is responsible for the dominant loads present at the corroded (thinned) portion of the SX riser pipes. The thermally induced loads and deadweight combine to create a compressive stress on one side of the SX riser pipes. Compressive stresses within the thin walled SX pipe create a condition subject to buckling type failures, and should have been evaluated to determine if the corroded SX riser pipes could operate without failure.

For the degraded 0E SX riser pipe, the licensee determined (reference EC 366395) that the minimum required pipe wall thickness (applicable to any SX riser pipe) was 0.121 inch, and concluded that 0E SX riser was compliant with the original design Code based on a minimum measured wall-thickness of 0.122 inch. To reach this conclusion, the licensee erroneously performed the design reviews/checks as identified below.

The licensee erroneously applied only three of the five required load combinations (i.e., equations 8, 9B, 9C, 10, and 11, identified in the 1977 Edition of the American Society of Mechanical Engineers (ASME) Code Section III, Division 1, Subsection ND-3600). In this case, the licensee did not apply equations 10 and 11. If these equations had been applied, the result would have been a higher value for the minimum pipe wall thickness.

The licensee failed to evaluate the compressive (buckling) loads present within the thinned SX riser pipe wall. If the licensee had completed this check, the result would have been a higher value for minimum pipe wall thickness.

The licensee incorrectly applied equations to verify the functional capability of the piping as discussed in Byron Station Updated Final Safety Analysis Report (UFSAR) Section 3.9.3.1.3. To check the functional capability of the piping, the licensee used the methodology described in Calculation EMD-041200, Lesson Plan EMD-TP-1 Volume II, which is a project specific procedure for Byron/Braidwood. Per EMD-041200, the functional capability for piping with a diameter-to-thickness (D/t) ratio not exceeding 50 can be assured by verifying that service level C stresses are below the service level B allowable stresses. The licensee used this method to calculate the required wall thickness even though the D/t ratio for the nominal or degraded portions of the 0E SX riser pipe exceeded 50. The D/t ratio based on nominal pipe wall thickness was 64, and this ratio would be even higher in the pipe areas subject to corrosion induced wall loss. For D/t values exceeding 50, EMD-041200 provided different acceptance criteria than that applied by the licensee in EC 366395. If the licensee had completed this check correctly, the result would have been a higher value for the minimum pipe wall thickness.

For the degraded 0H SX riser pipe, the licensee determined (reference EC 367754) that the minimum required pipe wall thickness was 0.06 inch, and concluded that 0H SX riser was operable based on a minimum measured wall thickness of 0.085 inch. To reach this conclusion, the licensee erroneously performed the design reviews/checks as identified below.

The licensee used the 1977 version of the ASME Code, Section III, Appendix F and applied equations applicable to Class 1 components to the Code Class 3 riser pipe. Therefore, the licensee erroneously applied allowable stress values for Code Class 1 pipe material (Sm = 20,000 pounds per square inch (psi)) to the Code Class 3 SX riser pipe material. If the licensee had applied the appropriate lower allowable stress value corresponding to the Code Class 3 pipe material (Sh = 15,000 psi), the result would have been a higher value for minimum pipe wall thickness.

The licensee failed to evaluate the compressive (buckling) loads present within the thinned SX riser pipe wall. If the licensee had completed this check, the result would have been a higher value for minimum pipe wall thickness.

For the degraded 0B SX riser pipe, the licensee determined (reference AR 00685955) that the minimum required pipe wall thickness was 0.03 inch, and concluded that 0B SX riser was operable based on a minimum measured wall-thickness of 0.047 inch. To reach this conclusion, the licensee erroneously performed the design reviews/checks as identified below.

The licensee erroneously applied only the equations from EC 367754 that did not include thermal stress. If the licensee had applied equations which included thermal stress, the result would have been a higher value for minimum pipe wall thickness.

The licensee failed to evaluate the compressive (buckling) loads present within the thinned SX riser pipe wall. If the licensee had completed this check, the result would have been a higher value for minimum pipe wall thickness.

The team's concerns discussed above prompted the licensee to complete an evaluation of the minimum wall thickness required to withstand the compressive loads present in the degraded sections of these riser pipes. Based on this evaluation, the licensee calculated that the minimum pipe wall thickness to preclude a buckling failure (with no safety factors) was 0.134 inch. Because the measured minimum wall thicknesses on 0B, 0H, and 0E SX risers was below 0.134 inch, these SX risers were not in an acceptable condition for return to service. Further, the licensee had not considered the magnitude of potential errors in performing the UT measurements of pipe wall thickness for these evaluations. Based on observations discussed in Report Section 4OA3.6, the in-situ UT measured pipe wall thickness was subject to an average error of 0.1 inch.

The licensee documented these analysis errors in AR 00691325 and AR 00696417. In response to these errors, and as a corrective action for the degraded riser conditions, the licensee completed a new evaluation for the past operability of the SX risers as documented in EC 368389, "Evaluation of Past Operability of the SXCT [Essential Service Water Cooling Towers] Risers." The team reviewed and evaluated this analysis as documented in Report Section 4OA3.8.

Analysis: The team determined that failure to establish adequate design margins for continued service of the 0E, 0H and 0B SX risers was a performance deficiency that warranted a significance evaluation. The team further determined that the issue was within the licensee's ability to foresee and correct and could have been prevented as discussed in report Section 4OA3.3.

The original pipe design Code maintained margins to ensue the pipe material remains well within elastic material property ranges. The licensee analysis performed in support of past operability (Section 4OA3.8) demonstrated that elastic margins would not be maintained in the degraded pipe areas, and instead would be subject to plastic deformation within the pipe material limits. In particular, for SX riser pipes 0A, 0B, 0C, 0D, 0E, with multiple areas of pipe wall thickness below 0.1 inch and/or the presence of through-wall holes, local areas of the pipe were subject to plastic deformation. Because elastic material behavior under normal and accident loads was no longer assured, the team concluded, based on engineering judgment, that the SX riser pipes left in service had an increased probability of rupture.

The team determined the finding associated with this apparent violation was more than minor in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” because the degraded SX piping condition resulted in an increase in the likelihood of the loss of the SX system due to pipe failures, which directly affected the Initiating Events Cornerstone. It was also associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee failed to establish adequate design margins for continued service of the 0E, 0H and 0B SX risers which resulted in extended plant operation with an increased probability of riser pipe failures. The increased probability of riser pipe failures adversely affected the SX system reliability because a riser pipe failure could cause an unrecoverable loss or flow diversion from the SX basin water supply (i.e., UHS). If this flow diversion was greater than SX makeup capacity, a loss of the SX system would occur causing a loss of several other risk significant systems and components (e.g., emergency diesel generators, reactor coolant pumps, residual heat removal cooling heat exchangers, etc.).

The finding associated with this apparent violation was evaluated in accordance with IMC 0609.04, “Phase 1 – Initial Screening and Characterization of Findings.” In applying the SDP Phase 1 Screening Worksheet, the degraded SX risers were treated as a condition which could increase the likelihood of a loss of SX event. A loss of SX affected the Transient Initiator contributor under the Initiating Events Cornerstone and also affected the Secondary and Long-Term heat removal categories under the Mitigating Systems Cornerstone. In accordance with IMC 0609.04, “Phase 1 – Initial Screening and Characterization of Findings,” if the finding affects multiple reactor cornerstones, the finding should be assigned the cornerstone that best reflects the dominant risk of the finding. The degraded service water condition directly contributed to the increased probability for a loss of service water initiating event, which represented the dominant risk contributor for this finding. Therefore, this finding was assigned to the Initiating Events Cornerstone. Since this finding is related to pipe degradation, the potential for pipe rupture, and subsequent loss of inventory, the SDP Phase 2 guidance was not applicable. Specifically, no SDP guidance exists to estimate the increase in rupture frequency for the degraded SX riser piping and further, the risk significance of the finding is highly dependent on assumptions regarding the increased potential for pipe rupture and the degree of leakage given rupture. Therefore, in accordance with Item 6 of Table 3b of IMC 0609.04, where existing SDP guidance is not adequate to provide a reasonable estimate of the finding significance, the risk evaluation is required to be performed in accordance with IMC 0609, Appendix M, “Significance Determination Process Using Qualitative Criteria.” The NRC performed a Phase 3 significance evaluation using IMC 609 Appendix M, which is discussed in Report Section 4OA3.8. As a result of this analysis, the finding associated with this apparent violation was characterized as having low to moderate safety significance (preliminary White).

The cause of this apparent violation was related to the Resources Component (Item H.2(a) of IMC 305) for the cross-cutting area of Human Performance, because the licensee failed to maintain plant safety by maintaining design margins. Specifically, these degraded riser pipes remained in-service without establishing adequate design margins in these engineering evaluations to justify continued service.

Enforcement: During an NRC inspection conducted between October 23, 2007, and February 14, 2008, two examples of an apparent violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," were identified.

Title 10 CFR 50, Appendix B, Criterion III, "Design Control," requires, in part, that design control measures provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above,

On July 11, 2007, the licensee's design control measures failed to verify the adequacy of the design of the degraded 0E SX riser pipe, in that, the methodology and design inputs used did not include significant factors (e.g., thermal stress, compressive loads (buckling) and functional capability) which affected the structural integrity of this degraded riser pipe. Specifically, as documented in EC 366395, "Nonconformance Evaluation for Line 0SX97AE-24 Near Valve 0SX163E," the licensee failed to check the thermal stress in accordance with Equations 10 and 11 from the ASME Code, 1977 Edition, Section III, Division 1 Subsection ND-3600; failed to evaluate the compressive (buckling) loads present within the thinned SX riser pipe wall; and failed to check the functional capability in accordance with the site procedures that implemented UFSAR Section 3.9.3.1.3 requirements for Class 2 and 3 piping. Consequently, the licensee incorrectly concluded that the minimum pipe wall thickness was sufficient to meet Code allowable stress levels, and the degraded 0E SX riser was left in service until October 20, 2007.

On October 12, 2007, and October 17, 2007, the licensee's design control measures failed to verify the adequacy of the design of the degraded 0H and 0B SX riser pipes, in that, the methodology and design inputs used did not apply an appropriate allowable stress value, and did not account for compressive stresses. Specifically, as documented in EC 367754, "OP EVAL 07-009, SXCT Riser Piping Below Minimum Wall Thickness," and in AR 00685955, the licensee failed to apply the lower allowable stress (Sh) values applicable to Class 3 piping, and did not evaluate the compressive (buckling) loads present within the thinned SX riser pipe wall. Consequently, the licensee incorrectly concluded that the pipe wall thicknesses were sufficient to meet Code allowable stress levels, and the degraded 0H and 0B SX risers were left in service until October 20, 2007.

Because the licensee replaced the degraded sections of SX piping and implemented adequate initial extent of condition reviews, an immediate safety hazard no longer exists. The licensee entered this finding into the corrective action program (AR 00691325). This is an apparent violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," pending completion of a final significance determination (AV 05000454/2007009-03(DRS); AV 05000455/2007009-03(DRS)).

.5 Evaluate the adequacy of the repair plan and monitor implementation. Confirm compliance with ASME Code requirements and the methodology to show this compliance and evaluate the licensee's conclusions regarding the need or lack thereof for ASME Code relief.

a. Inspection Scope

The team observed and reviewed activities associated with the replacement of the degraded SX riser pipe to determine if these activities complied with the ASME Code Section IX, Section XI, and Section V Code requirements and licensee procedures.

b. Findings and Observations

Within each of the eight vault type enclosures, a 24 inch diameter ASME SA106 Grade B carbon steel riser pipe runs vertically up through the concrete floor and terminates at a flange which supports a discharge isolation valve. Although, the SX riser vaults are enclosed, rainwater can enter through the roof/door interface and wind driven spray from the SX cooling tower outfall can enter through sheet metal panels forming the backwall of the riser vaults. The floor of each of the riser vaults is sloped to allow water to flow into drain holes (typically two) at the corners of the vault floor. However, water intrusion into these vaults has contacted the uncoated carbon steel riser pipe providing a semi-continuous wetted environment, which caused significant external corrosion and wastage around the pipe perimeter just above the concrete floor elevation (Attachment 3, Pictures Nos. 1, 2, 3, 4 and 5). The corroded portion of riser pipe extends vertically four to six inches in height between the concrete floor and the support flange for the motor operated discharge isolation valves (0SX163A(B)(C)(D)(E)(F)(G)(H)).

The licensee removed a portion of the concrete floor surrounding each of the SX riser pipes for a depth of about eight-to-twelve inches. The licensee then performed UT pipe wall thickness measurements of the piping section below the floor grade at a location a few inches above the bottom of the concrete excavation. The pipe wall thickness measured at this location was typically greater than the nominal wall thickness of 0.375 inch. The licensee next used a cutting machine to make a horizontal cut at this location and removed the degraded section of riser pipe. The licensee then fit up and welded in a new section of 24 inch diameter carbon steel pipe and flange. Following replacement, the licensee applied a protective coating to the exterior surface of the riser pipes to prevent corrosion.

During the replacement process described above, the team observed portions of the licensee replacement activities. Specifically, the team observed concrete removal/excavation, SX riser pipe cutting and removal, grinding preparation for weld fit up of replacement riser pipe sections, field welding of new riser pipe, shop welding of riser pipe flanges, and non-destructive examination of riser pipe and welds. The team also interviewed welders, reviewed the weld procedures and materials used for welding the replacement riser pipe to confirm this welding was controlled and qualified in accordance with the ASME Code Section IX requirements. Based upon this review, no deviations from the ASME Code requirements were identified.

.6 Evaluate the adequacy of the licensee's plans regarding the condition and operability of SX riser piping for restarting the Units and any subsequent repairs. Include the adequacy of the licensee's decision to choose risers OF and OG for destructive evaluation in order to provide insights for subsequent decisions regarding riser OD. Also include review of the revision to ECC 0000367082 regarding change in required number of cooling tower fans.

a. Inspection Scope

The team reviewed and evaluated the licensee's engineering changes supporting return of degraded risers and modified equipment to service in support of Unit 1 and Unit 2 restart. The team also reviewed and evaluated the use of nondestructive measurements for SX riser pipe wall thickness in support of licensee contingency plans to return the degraded 0D SX riser to service without repair.

The team reviewed EC 367082, "Operability Evaluation 07-008, UHS Capability with Failure of SX Fans," to determine if the results supported the SX system configuration for Unit 1 and Unit 2 restart.

b. Findings and Observations

b.1 Accuracy of Nondestructive Testing for SX Riser Pipe Wall Thickness

For the 0B, 0E, 0F and 0H SX riser pipes, the licensee had removed rust at small localized areas of the riser pipe surface to perform in-situ UT pipe wall thickness measurements. For these riser pipes, the licensee elected to not apply surface cleaning methods which could further reduce the pipe wall thickness (e.g. grinding). Instead, the licensee elected to use non-intrusive cleaning methods (e.g. hand held scrapers) to create small rust colored spot areas with a relatively smooth texture to facilitate UT wall thickness measurements. The team noted that the non-intrusive cleaning methods did not result in a bright metal surface nor was a flat surface obtained to facilitate accurate UT wall thickness measurements. Because of these limitations, the licensee's nondestructive examiners had recorded these in-situ UT wall thickness measurements as a "best effort UT." The team evaluated the accuracy of the in-situ UT measured pipe wall thickness by comparing in-situ results to post-removal wall thickness measurements recorded for the 0F SX riser pipe.

The licensee removed the 0F SX riser pipe section and stored it in a quarantined area of an on-site warehouse and cleaned the exterior surface to bright metal by abrasive grit blasting. The licensee performed UT and micrometer thickness measurements of the cleaned riser. The average in-situ wall thickness measured for the 0F SX riser pipe was 0.1 inch based on 17 UT data points recorded on October 20, 2007, at local spot areas with external rust removed (but not to shiny metal). On October 27, 2007, the average post-cleaning 0F SX riser pipe wall thickness measured with UT at 74 data points was 0.233 inch. The average post-cleaning 0F SX riser pipe wall thickness measured with a micrometer at 74 data points was 0.198 inch. The team compared the in-situ and post removal average wall thickness measurements taken along a common horizontal plane representing the most degraded section of the 0F SX riser pipe (Attachment 3, Picture No. 6). Based on this comparison, the in-situ UT measurements of SX riser pipe wall thickness were subject to an average error of approximately 0.1 inch. The licensee documented its "best effort" UT readings in AR 00690882.

To support a more accurate assessment of the 0D SX pipe wall condition (for potential return to service), the licensee performed in-situ grit blasting to clean external rust from the 0D SX riser pipe. The grit blasting achieved a shiny metal surface condition which facilitated more accurate UT pipe wall thickness measurements (Attachment 3, Picture No. 7). The licensee also measured and recorded localized external pits using a mechanical depth gauge. On October 27, 2007, the licensee recorded a minimum average pipe wall thickness of 0.189 inch for the 0D SX riser pipe based on 25 data points. The licensee also identified a 3 inch long horizontally oriented gouge with a minimum remaining pipe wall thickness of 0.096 inch at the bottom of this gouge. The licensee ultimately elected to repair the 0D SX riser instead of returning this degraded riser to service as discussed in the following report section.

The team concluded that the licensee made an appropriate decision in selection of the 0F SX riser for comparison of non-destructive evaluation results in order to provide insights for the licensee's decision associated with placing the unrepaired 0D SX riser back into service. The team also concluded that the licensee had appropriately selected SX risers 0B, 0C and 0H for destructive analysis, because they represented a more significantly degraded condition than the 0G SX riser pipe. Specifically, the 0B and 0C SX riser pipes contained through-wall holes with substantial areas of wall loss and were representative of the most severe corrosion processes affecting the SX riser pipes (see report Section 4OA3.8).

b.2 <u>Inadequate Design Margins for 0D SX Riser Pipe Configurations For Restart</u>

From October 24 through October 28, 2007, the team reviewed licensee plans to return the 0D SX riser pipe to service without repair of the degraded riser pipe section. The team identified errors which constituted violations of NRC requirements of minor significance in the engineering design changes intended to allow continued service for the 0D SX riser in support of Unit 1 and Unit 2 restart.

To assess the serviceability of the 0D SX riser, the licensee initially calculated the minimum allowable wall thickness based on the original design of the SX pipe. Specifically, the licensee issued EC367974 to establish the minimum allowable pipe wall thickness for the 0D SX riser pipe based on the ASME Code Section III requirements. However, the team identified that the licensee failed to correctly check the functional capability as required by the UFSAR Section 3.9.3.1.3. To check the functional capability of the SX pipe, the licensee established a methodology described in calculation EMD-041200, Lesson Plan EMD-TP-1, Volume II, which is a project specific procedure for Byron/Braidwood. For the 0D SX riser pipe, the licensee erroneously checked the functional capability for the SX pipe by verifying that Service Level "C" stress was below the Service Level "B" allowable stress. EMD-041200 provided for this method of checking functional capability only when the pipe diameter-to-thickness (D/t) ratio did not exceed 50. For the 0D SX riser pipe the D/t ratio based on the nominal pipe wall thickness was 64, and in the corroded section of pipe the D/t ratio was even larger. EMD-041200 provided a different evaluation method and acceptance criteria for D/t values which exceeded 50. Failure to apply the applicable methods and acceptance criteria to check the functional capability in accordance with the original design requirements is a violation of 10 CFR 50 Appendix B, Criterion III "Design Control" of minor significance, because the minimum required pipe wall thickness was not controlled by the functional capability criterion in this case. The licensee captured this issue in the corrective action system AR 00691349.

Because portions of the 0D SX riser pipe fell below the calculated minimum design wall thickness, the licensee initially attempted to demonstrate that the riser pipe was acceptable for return to service without further repairs or modifications based on operability criteria. The licensee evaluated the dead weight and the thermal and seismic loads present for the 0D SX riser pipe and determined that the limiting load combination resulted in a compressive (buckling) load at the degraded portion of the riser pipe. The licensee issued EC 367967 to establish the minimum pipe wall thickness for operability based on the limiting/dominant compressive (bucking) loads present in the degraded 0D SX riser pipe. However, the team identified that the licensee failed to establish a factor of safety (i.e., design margin) to account for uncertainty in the buckling loads. Specifically, the licensee had changed the normal design factor of safety from 1.8 to 1.0 in this EC without establishing an appropriate technical basis. In Code Case N-284-1 approved by the NRC for use in evaluation of degraded Code Class MC components, the NRC had accepted a factor of safety of 1.34 for buckling loads under Service level “D” conditions (this is typical for operability limits). For the 0D SX riser pipe, the licensee decision to remove the factor of safety (i.e., 1.0 safety factor) for buckling failure was not appropriate given the level of uncertainty for UT wall thickness measurements as discussed above. Failure to apply the appropriate safety factors (consistent with the ASME Code or NRC approved Code Case) to minimum wall thickness calculations for buckling loads is a violation of 10 CFR 50 Appendix B, Criterion III, “Design Control,” of minor significance because the licensee did not return this riser to service based on this inadequate calculation. The licensee captured this issue in the corrective action system (AR 00690398).

For the 0D SX riser, the licensee next proposed installation of a support member welded to the riser pipe flange to allow returning the 0D SX riser pipe to service without additional pipe repairs. Specifically, the licensee issued EC 367937 to establish the design for this welded support attached to the pipe flange, which was intended to carry the compressive loads for the degraded SX riser pipe and preclude a buckling type failure. However, the team identified that the licensee failed to apply the applicable design criteria for an ASME Section III Code support. Instead, the licensee applied equations and acceptance criteria from Appendix F of Section III of the ASME Code, for service level “D” conditions. Appendix F was applicable for evaluating operability of degraded and non-conforming conditions, but was not consistent with the original design requirements for a Code Class 3 integral support member. Failure to apply the appropriate formula and acceptance criteria is a violation of 10 CFR 50 Appendix B, Criterion III, “Design Control,” of minor significance because the licensee did not return this riser to service based on this inadequate support calculation. The licensee captured this issue in the corrective action system (AR 00690315).

For the 0D SX riser, the licensee next proposed installation of a single strut type lateral support member attached to the riser vault wall. Specifically, the licensee issued EC368032 to establish the design for this lateral support, which was intended to reduce the thermally induced stress at the degraded SX riser pipe section. However, the team identified that the licensee failed to establish the appropriate loading conditions such that this support member, designed for compressive loads, could in fact, be subjected to a substantial tensile load. The original SX pipe design was based on a pipe temperature of 125 degrees Fahrenheit, which would cause expansion in the pipe and subjected the support design to compressive loads. For one condition modeled in the piping analysis, PIPSYS, the licensee had assumed that the piping downstream of the valve could cool down to 35 degrees Fahrenheit (e.g., if the 0SX163D SX riser isolation valve was shut during winter conditions). The 35 degree Fahrenheit temperature condition resulted in shrinkage for the horizontal run of the riser pipe downstream of the 0SX163D SX riser isolation valve which created a tensile load on the temporary support. The team concluded that had this support design been implemented, the support may have failed under this tensile load condition. Failure to consider the tensile load conditions in design of this lateral support is a violation of 10 CFR 50 Appendix B, Criterion III, “Design Control,” of minor significance because the licensee did not return this riser to service with this inadequately designed support. The licensee captured this issue in the corrective action system (AR 00692030).

Because of the localized 3 inch long horizontally oriented gouge with a minimum remaining pipe wall thickness of 0.096 inch in the 0D SX riser pipe, the licensee attempted to demonstrate structural integrity of this limiting local thinned area by performing an evaluation in accordance with NRC approved Code Case N-513-2. However, the licensee reported that the results of this analysis were not acceptable and did not issue this evaluation.

The licensee’s efforts to demonstrate the acceptability of the degraded 0D SX riser for continued service, proceeded in parallel with installation of line stops for isolation of the 0A and 0D SX riser pipes to affect permanent repairs. Because these line stops were installed prior to plant restart, the licensee did not implement the configurations discussed above, which involved returning the degraded 0D SX riser pipe to service. On October 30, 2007, the licensee restarted both Units after replacement of degraded riser pipe sections for six of the eight SX riser pipes and after installation of line stops for isolation of the two remaining unrepaired riser pipe sections (0A and 0D SX riser pipes). The licensee subsequently completed replacement of these two remaining degraded riser pipes and returned them to service.

b.3 Evaluation of EC 367082 UHS Temperature Limits-Tornado Events

The licensee issued EC 367082, “Operability Evaluation 07-008, UHS Capability With Loss of SX Fans Due to a Tornado,” to determine the maximum SX system operating temperature rise based on a reduced number of cooling tower fans available following damage caused by tornado induced missiles. For the limiting case (only 3 fans available due to tornado missile damage and single failure), the licensee concluded that the maximum SX system basin water temperature would remain below the design temperature limit of 100 degrees Fahrenheit. In this calculation, the licensee also demonstrated that with six fans in service under the most limiting heat load transients, the maximum SX temperature would reach 90 degrees Fahrenheit. The team confirmed this result by verifying that the maximum SX temperatures during the dual Unit shutdown for this SX event remained below 90 degrees Fahrenheit as predicted by this analysis. Because the licensee restarted Unit 1 and Unit 2 with six cooling towers available for SX system service, no operational limitations existed for the UHS temperatures.

.7 Evaluate suitability and risk significance of the licensee's decisions and actions regarding not following direction in the Byron Technical Requirement's Manual to isolate piping after identifying a leak in the SX riser.

a. Inspection Scope

The team reviewed operator logs and interviewed licensee personnel involved in making decisions associated with application of the Technical Requirements Manual (TRM) Section 3.4.f requirements for structural integrity of ASME Code 3 components, after discovery of a leak at the 0C SX riser pipe. The team performed this review to assess the suitability of licensee decisions and to determine if a violation of TRM requirements occurred.

b. Observations and Findings

b.1 Decision to Not Isolate Leaking SX Riser Pipe

On October 19, 2007, during rust removal from the 0C SX riser pipe near valve 0SX163C in preparation for pipe wall thickness measurements, a ½ inch diameter leak occurred (Attachment 3, Picture No. 3). The licensee determined that the 0C SX riser leak constituted a loss of structural integrity and consequently declared the UHS inoperable and shut down both Units due to entry into Technical Specification 3.7.9, Condition G.

TRM 3.4.f Condition B requires that with the structural integrity of one or more ASME Code Class 3 component(s) not in conformance, the licensee complete either Required Action B.1, "Restore the structural integrity of the affected component to within its limits," or, complete Required Action B.2, "Isolate the affected component." Whichever Required Action the licensee chooses to implement must be completed "Immediately," meaning the Required Action "should be pursued without delay and in a controlled manner." (reference definition of "immediately" in the TRM Section 1.3)

Documents generated during the event show that licensee staff mistakenly believed that the circumstances required isolation of the leaking 0C SX riser pipe under Required Action B.2 of TRM 3.4.f and did not permit entry into Required Action B.1. to restore the structural integrity of the component. However, the licensee did not attempt to isolate the leak. Several documents indicate the licensee believed that a departure from required Action B.2. was needed to minimize safety risks during shutdown:

- In AR 00687042, the licensee stated, "Operations Management, Regulatory Assurance and Corporate Licensing believe it is reasonable to depart from the TRM TLCO in this particular situation and is in the better interest of protecting the health and safety of the public."

- In AR 00687042, the licensee stated, "In order to comply with this TLCO action the entire OA UHS tower would have to be isolated. This would mean placing both Units in a shutdown transient with key safety equipment, such as both 1A and 2A diesel generators intentionally made inoperable due to the requirement to isolate the C riser pipe. This is considered an online risk orange condition for both Units. Given the nature and location of the leak, Operations Management believes the OA UHS can safely remain in service and have this safety equipment available for use if needed during the shutdown transient."

The licensee's operations staff were also aware that the isolation valves between the SX trains had gross leakage and would not have been effective in achieving isolation of the leaking 0C SX riser pipe. Accordingly, the licensee did not attempt to isolate the 0C SX riser pipe leak. The licensee considered whether to implement a procedure change to deviate from Required Action B.2, but decided not to, because the licensee believed the procedure change would take too long.

At the time the licensee staff made the decision to not isolate the leaking 0C SX riser, little or no information existed to characterize the overall condition of the 0C SX riser pipe. Without this information, the licensee staff implicitly accepted the risk that the leaking pipe could have developed into a larger break type failure, during the time it took to shutdown both Units and affect repairs.

Given the licensee's mistaken belief that TRM 3.4.f required isolation of the 0C SX riser pipe, the team did not believe that the licensee made an appropriate decision to deviate from this requirement without following the procedure change process. The team noted though, that isolation was not the only option allowed by TRM 3.4.f, because the licensee could also have opted to "immediately" restore the structural integrity of the leaking riser pipe.

After review of these requirements by Regional Counsel and staff members from the Office of Nuclear Reactor Regulation (NRR), the NRC concluded that the licensee's actions to shut down the plant, install line stops, and repair the leaking riser pipe had complied with Required Action B.1 of TRM 3.4.f for restoration of structural integrity without delay and in a controlled manner. During this time, the 0C SX riser pipe leakrate was well within the capacity for SX system makeup, so the SX system did not experience any operational transients. Therefore, the licensee decision to leave this riser in service was suitable in that it did not result in adverse SX system operational consequences and the team did not identify any deviations from the TRM requirements.

b.2 <u>TRM Change Bypasses Procedure Change and Safety Evaluation Processes</u>

<u>Introduction</u>: The team identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," for the licensee's failure to ensure that Revision 54 of the TRM was appropriate to the circumstances. Revision 54 of the TRM was not appropriate to the circumstances because it allowed deviations from the TRM requirements without following the procedure change process and 10 CFR 50.59 review process.

<u>Description</u>: On October 31, 2007, the team identified that the licensee issued Revision 54 to the TRM, which allowed deviations from TRM requirements without following the procedure change process and 10 CFR 50.59 review process.

On October 27, 2007, the licensee issued TRM Change No. 07-015 (Revision 54 to the TRM). In this change, the licensee added Section 1.5.d, applicable to the entire TRM, which stated, "Reasonable action may be taken that departs from a TRM requirement when this action is immediately needed to protect the public health and safety and no action consistent with the TRM requirements that can provide adequate or equivalent protection is immediately apparent. Shift Manager approval is required to depart from a TRM requirement. These actions and their basis shall subsequently be documented in the Shift Manager's log and entered into the corrective action program." The licensee considered this TRM option necessary, because some situations (as discussed above for the SX riser pipe leak) required completion of TRM actions faster than deviations from these actions could be authorized under the procedure change process.

Revision 54 of the TRM would have allowed the licensee staff to deviate from any, or all TRM requirements, without using the procedure change process, and without completing a review in accordance with10 CFR 50.59 requirements, to determine if a license amendment was required for these TRM deviations. The team was concerned that without this review, or establishment of a written process for completing this review, the licensee had not demonstrated that the proposed TRM deviations would be safe, or that these actions could be authorized without an NRC approved license amendment. The licensee subsequently removed the option to deviate from the TRM requirements and entered this issue into the corrective action program (AR 00692498).

Analysis: The team determined that failure to ensure that Revision 54 of the TRM was appropriate to the circumstances was a performance deficiency that warranted a significance evaluation.

The team determined the finding was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," because the finding was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Absent NRC intervention, the licensee's procedure option could have allowed unsafe deviations from the TRM required actions or allowed actions which would have required prior NRC approval (e.g., license amendment).

The team evaluated the finding in accordance with IMC 0609.04, "Phase 1 – Initial Screening and Characterization of Findings." Under the Mitigating Systems Cornerstone Column of Table 4a, the team answered "No" to each of the Mitigating System Cornerstone screening questions, because the NRC identified this deficient change prior to the licensee implementing any actions which adversely affected the structural integrity or operability of mitigating systems. Therefore, the finding screened as having very low safety significance (Green).

The cause of this finding was related to the Decision Making Component (Item H.1(b) of IMC 305) for the cross-cutting area of Human Performance, because the licensee failed to make conservative assumptions in decisions affecting the procedure adherence for safety related systems. Specifically, the licensee's assumptions for implementing this procedure option was not based on a comprehensive review of system alignments for all possible TRM deviations, and thus did not demonstrate that the proposed TRM deviations allowed would be safe.

Enforcement: During an NRC inspection conducted between October 23, 2007, and February 14, 2008, a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings" was identified.

Title 10 CFR 50 Appendix B, Criterion V, “Instructions, Procedures and Drawings,” requires in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances, and shall be accomplished in accordance with these instructions, procedures, or drawings.

Contrary to the above, On October 27, 2007, the licensee failed to ensure that Revision 54 of the TRM (Change 07-015) was appropriate to the circumstances. Specifically, Revision 54 authorized the licensee staff to deviate from any, or all, TRM requirements without using the procedure change process and without completing a review to determine if prior NRC approval was required (e.g., license amendment). Because this finding was of very low safety significance and because the finding was entered into the licensee's corrective action program (reference AR 00692498), this violation is being treated as a Non-Cited Violation (NCV 05000454/2007009-04; NCV 05000455/2007009-04) consistent with Section VI.A of the NRC Enforcement Policy.

.8 Evaluate the risk significance of the as-found condition (before and after the leak) regarding the SX riser piping degradation.

a. Inspection Scope

The team reviewed licensee measurements of SX riser pipe wall thickness, laboratory test report, past operability evaluation, structural integrity calculations, and licensee risk evaluations to evaluate the operability and risk significance of past operation with the degraded service water pipe risers.

b. Observations and Findings

b.1 As-Found Condition of SX Riser Piping

In BYR-71886, “Evaluation of Corrosion of Byron SX Cooling Tower Risers,” the licensee documented a detailed evaluation of the as-found condition of the carbon steel riser pipes which included metallurgical and laboratory test results from the removed 0B, 0C and 0H SX riser pipe sections. In BYR-71886, the licensee characterized the 0C SX riser pipe external corrosion deposits as follows: “On the external surface of the riser, the C1 hole was surrounded by a mound of black and orange corrosion products that measured up to ¾ inch tall. At the time of the field inspection, the external corrosion mound was hard, adherent, and very difficult to remove” and, “Away from the C1 leak, the external pipe and flange surfaces were covered with layered corrosion deposits that were typically less than 3/8 inch thick. The corrosion products were primarily black and orange, except on the outer surface where thin white deposits were observed. Several samples of the external layered corrosion products were collected for lab evaluation” and, “During the removal of the 0C riser, portions of the external corrosion mound that surrounded the C1 hole fell off. This loss allowed for a visual inspection of the surface surrounding the hole, which revealed the C1 leak was the result of an external pit that was located within a larger area that was thinned by general corrosion.” In this report, the thin white deposits were tested and found to be consistent with calcium carbonate mineral deposits believed to be concrete dust deposits caused by floor removal activities (e.g., jack hammering).

The SX riser pipes carry water typically at 75 to 100 degrees Fahrenheit and 15 to 35 psi of internal pressure. The original riser pipe wall thickness was a nominal 0.375 inch, but significant external corrosion and wastage had occurred around the pipe perimeter just above the concrete floor elevation (Attachment 3, Pictures Nos. 1, 2, 3, 4 and 5). The corrosion reduced the pipe wall thickness for each of eight SX carbon steel riser pipes and affected the portion of riser pipe which extended vertically four to six inches in height above the concrete floor. Following removal and cleaning of the degraded riser pipe sections, the licensee performed pipe wall thickness measurements (typically with a micrometer) to assess the pipe condition. Based on the licensee's non-destructive examination reports, the team identified the following information, which represented the as-found pipe wall condition for the most degraded sections of the SX riser pipes.

0A Riser - Four pipe wall areas below 0.1 inch which extended for several inches along the pipe perimeter. Average pipe wall thickness of 0.190 inch.

0B Riser -One corrosion product filled elliptical hole was identified with a maximum length dimension of 0.74 inch. One pipe wall area reduced to approximately 0.1 inch thick. Average pipe wall thickness of 0.203 inch.

0C Riser - Four holes were identified (three at approximately 0.5 inch diameter and one at approximately 0.18 inch diameter). Three holes were filled with corrosion products. Six pipe wall areas reduced to below 0.1 inch, three of which extended for several inches along the pipe perimeter. Average pipe wall thickness of 0.168 inch.

0D Riser - Eight pipe wall areas reduced below 0.1 inch, which extended for several inches along the pipe perimeter. One area was characterized as a three inch long gouge in the pipe wall. Average pipe wall thickness of 0.148 inch.

0E Riser - Three pipe wall areas reduced below 0.1 inch, one of which extended for several inches along the pipe perimeter. Average pipe wall thickness of 0.168 inch.

0F Riser -No localized areas below 0.1 inch. Average pipe wall thickness of 0.198 inch.

0G Riser - No localized areas below 0.1 inch. Average pipe wall thickness of 0.183 inch.

0H Riser -One local thin area (gouge) 0.080 inch believed to have been caused by a mechanical process (e.g. cutting or grinding). Average pipe wall thickness of 0.252 inch.

Note – The average SX riser pipe wall thickness above is the minimum average pipe wall thickness recorded in Table 3 of Structural Integrity Calculation EXLN-30Q-301, "Operability Evaluation of Essential Service Water (SX) Cooling Water Risers, Byron Station."

b.2 Past Operability of the As-Found Condition of SX Riser Pipes

As a corrective action for the degraded riser conditions and in response to errors made in prior evaluations of SX riser operability (Report Section 4OA3.4), the licensee completed EC 368389, "Evaluation of Past Operability of the SXCT Risers." In this analysis, the licensee concluded that the 0B and 0C SX riser pipes would have leaked, but not ruptured under design basis loads. Further, the licensee concluded that the amount of leakage from the through-wall holes in the 0B and 0C SX riser pipes would not have prevented the SX system from providing adequate cooling for plant components. Therefore, the licensee concluded that the UHS was operable during past periods of operation with the degraded SX riser piping. The team reviewed this evaluation and supporting calculations to determine if the licensee's assumptions and inputs were adequate to confirm past operability of the SX riser pipes, SX system and the UHS. The team requested the licensee staff provide any site procedures and guidance that it used to determine the past operability of the degraded SX riser pipes. The licensee staff stated that site and corporate operability procedures only applied to current operability evaluations, and that no requirements or guidance existed for performing past operability evaluations. The licensee documented this lack of procedural guidance in AR 00696316.

0B and 0C SX Riser Pipes Not Operable

The team identified that the licensee's use of the ASME Code Section III, Appendix F methods and acceptance criteria for demonstration of operability for the 0B SX and 0C SX risers was not appropriate. The licensee's past operability approach was based on an elastic-plastic finite element analysis with methods and acceptance criteria derived from Section III, Appendix F. However, Appendix F, Article F-1200 states, "the Level D Service Limits and design rules contained in F-1300 are provided for limiting the consequences of the specified event. They are intended (NCA-2142) to assure that violation of the pressure retaining boundary will not occur, but are not intended to assure operability of components either during or following the specified event." In this case, the 0B and 0C SX riser pipes contained through wall rust-filled holes which "violated" the pressure retaining boundary (i.e., carbon steel pipe wall material). The NRC established methods for evaluating operability of piping systems with a through-wall flaw or operational leakage are identified in Part 9900 of the NRC inspection manual Sections C.11 and C.12. In these sections, the NRC approved methods for demonstration of operability of a pipe with a through-wall flaw or operational leakage, was by application of methods and acceptance criteria found in Code Case N-513-1, "Evaluation Criteria for Temporary Acceptance of Flaws in Moderate Energy Class 2 or 3 Piping," or GL 90-05, "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping." These NRC endorsed methods included safety margins to ensure the pipe materials retain elastic properties. For example, Code Case N-513-1 required a 2.77 factor for margin-of-safety under normal service loads (i.e., service level A and B load conditions) and a 1.39 factor for margin-of-safety under accident loads (i.e., service level C and D load conditions). Because the licensee selected an analysis method which allowed plastic deformation (Appendix F) instead of following NRC approved analysis methods that ensured elastic material behavior, the team concluded that the 0B and 0C SX riser pipes were not operable.

Six SX Riser Pipes Demonstrated Operable

For the remaining six SX risers, the team concluded that the licensee's use of the ASME Code Section III, Appendix F methods and acceptance criteria was appropriate because the pressure boundary had remained intact for these risers. Specifically, the licensee conclusions for SX riser pipe structural integrity was based on vendor calculations EXLN-30Q-302, "Operability Evaluation of Essential Service Water (SX) Cooling Water Risers, Byron Station," and EXLN-30Q-301, "Operability Evaluation of Essential Service Water (SX) Cooling Water Risers, Byron Station," which utilized results from finite element analysis modeling of the degraded riser pipes in the as-found condition. Four bounding analytical models were developed based on the remaining wall thickness profiles for the 0C, 0D, 0E and 0G riser pipes. The team with support from NRR staff reviewed Calculations EXLN-30Q-302 and EXLN-30Q-301 to determine if the licensee had completed an appropriate analysis which considered uncertainties in the inputs, assumptions and computer modeling parameters.

The licensee completed sensitivity studies for parameters which affect the accuracy of the analytical models developed for the SX riser pipes. Specifically, the licensee considered sensitivity to: changes in analytical mesh size and element type, pipe-to-concrete gap size, riser flange fillet weld size, riser height measurement uncertainty, pit hole size uncertainty, 2 inch branch pipe affects on displacement and stiffness, and isolation valve affects on the center-of-gravity. The team identified that the licensee's analysis lacked a sensitivity study for potential errors in recording the azimuth locations of the degraded pipe areas. Specifically, in Appendix A of EXLN-30Q-301, the licensee stated, "Marking of the grid marks on the pipe stubs was not necessarily done consistently." In this same appendix, the licensee resolved this issue by completing a sensitivity study to bound errors for riser pipe height with respect to grid locations. This study did not include potential errors in recording the azimuth location caused by lack of procedure controls to establish a consistent method to orient the pipe grid with respect to a known azimuth location. Without a consistent azimuth location to start the grid pattern numbering, a substantial error could be introduced in azimuth locations for the more degraded pipe wall areas. In this case, buckling failures would be sensitive to the azimuth locations of thinned areas with respect to compressive loads. The team's observations prompted the licensee to identify a 2 inch tolerance in azimuth uncertainty and to perform a sensitivity study for the D-riser model which evaluated the impact of this uncertainty. Based on this sensitivity study, the original analysis results (stress, strain and displacements) were replicated within 3 percent and, therefore, the original analysis conclusions remained valid.

The ASME Code Section III, Appendix F, Article F-1310(e) states that the potential for unstable crack growth shall be considered. The licensee did not perform this evaluation because examinations of the corroded pipe had not identified cracks and the licensee did not believe that the through wall holes would promote cracking. The team concluded that this was a reasonable presumption for the carbon steel pipe material, which generally has good ductility and no active service related cracking mechanisms.

The licensee calculations demonstrated for internal events and seismic loads within design basis, that a margin remains to plastic strain induced material failure limits (up to 7 percent plastic strain predicted). The typical maximum plastic strain of carbon steel under axial loading is about 30 percent, so based on engineering judgment; the team concluded that the six non-leaking SX riser pipes were operable.

Overall SX system and UHS Demonstrated Operable

In EC 368389, the licensee concluded that the amount of leakage from the through-wall holes in the 0B and 0C SX riser pipes would not have prevented the SX system from providing adequate cooling for plant components. Specifically, the licensee demonstrated that sufficient makeup capability existed to ensure that the SX system could maintain adequate cooling and maintain sufficient SXCT basin inventory to account for SX leakage flow out the holes in these riser pipes. The team did not identify any significant errors in the licensee's evaluations and concluded that the SX system and UHS were capable of performing their safety functions in the as-found condition (e.g. operable).

b.3 <u>Risk Significance of the Degraded SX Riser Piping</u>

The result of a Phase 3 SDP analysis conducted for the preliminary significance determination was a White finding for two apparent violations which affected the Initiating Events and Mitigating Systems Cornerstones. The result was obtained using Inspection Manual Chapter 0609 Appendix M, "Significance Determination Process Using Qualitative Criteria." This result is based on a qualitative analysis which considered the degree and extent of SX riser degradation, the period of time the degraded condition existed, the potential plant safety impact of an SX riser rupture, and plant mitigating features and strategies for a riser failure as discussed in the following paragraphs.

Although the degraded riser pipes did not result in an inoperable condition for the SX system or UHS, the condition of the riser pipes represented an increase in the probability of SX system failure (e.g. decreased SX system reliability). Because the degraded riser pipes were common to each Unit's SX system, a potential existed for a common mode failure of the SX systems affecting both Units. The performance deficiencies which contributed to the degraded riser pipe condition and the application of the Phase 1 SDP are identified in Sections 4.O.A.3.3 and 4.O.A.3.4 of this report.

From a risk perspective, one or more pipe ruptures could result in a loss of SX event if the leakage from the risers exceeded the SX basin makeup capability. The required makeup and the available makeup capabilities are both dependent on the postulated scenario and as a result, the rupture size that could result in a loss of SX event varies depending on these factors. In addition, the SX risers are enclosed in concrete vaults adjacent to the cooling tower basin which also may impact the postulated rupture event by providing a hold-up volume and possible return path to the basin. In all scenarios, the pipe rupture would need to be large to impact the function of the SX system.

If a loss of SX event did occur as a result of pipe rupture(s), operators would implement abnormal operating procedures to align the fire protection system to the charging pump lube oil cooler to continue reactor coolant pump (RCP) seal cooling and prevent a seal loss of coolant accident (LOCA). A loss of SX event followed by the failure of these operator actions represents the dominant risk sequence for this finding. Another potential mitigating strategy includes aligning the fire protection or non-essential service water system to supply the SX system. Given the large amount of water inventory in the basin, the NRC concluded that there would be sufficient time available for operators to take the mitigating actions for either strategy to limit the consequences of a postulated rupture event.

Quantitative risk insights supported the qualitative significance assessment. The NRC determined that the degraded condition of the SX riser piping represented an increase in the likelihood of a loss of SX event and also represented an increase in the failure probability of the SX system in response to other initiating events (i.e., other transients, loss of offsite power, seismic events, etc.). There is currently no SDP tool or method to estimate an increase in the probability of rupture of degraded piping. Because of that, the NRC used the conditional probability of rupture for service water piping from EPRI 1013141, "Pipe Rupture Frequencies for Internal Flooding PRAs," Revision 1, as an estimate for the pipe rupture probability given the degraded condition, and the NRC's Simplified Plant Analysis Risk Model (SPAR) for Byron, Revision 3.31, to develop quantitative risk insights. Although this represented the best available quantitative information, the NRC concluded that the lack of SDP tools and the large uncertainty in the increase in pipe rupture probability precluded using a quantitative risk analysis as the sole basis for the significance of the finding.

Due to the lack of suitable probabilistic risk assessment tools for these findings and the large uncertainty in estimating the increased likelihood of pipe rupture given the degraded condition, the criteria for using IMC 0609, Appendix M, "Significance Determination Process Using Qualitative Criteria" were met. Therefore, a Phase 3 SDP was completed in accordance with the qualitative criteria identified in Table 4.1 of Appendix M.

Using the criteria of Appendix M (Attachment 5), the finding was characterized as having low to moderate safety significance (preliminary White). The key criteria considered in the qualitative evaluation included the following:

- Quantitative risk evaluation results are highly uncertain and range from Green (very low safety significance) to Yellow (substantial safety significance) (IMC 609, Appendix M, Table 4.1, Decision Attribute 1)

- Operating experience (i.e., IN 2007-06) indicates that catastrophic failure of service water piping can occur as a result of external piping corrosion when the piping is subjected to normal operating conditions (IMC 609, Appendix M, Table 4.1, Decision Attribute 1)

- Estimates of the increased probability of rupture given the degraded state of the SX riser piping indicate that the likelihood of rupture is non-negligible, but rather low (IMC 609, Appendix M, Table 4.1, Decision Attribute 1).

- All eight risers experienced some degree of external corrosion, with at least five risers (0A, 0B, 0C, 0D, and 0E) having multiple areas of pipe wall thickness below 0.1 inch. For two of the risers (0B and 0C), pressure boundary integrity was not maintained as evidenced by existing rust-filled through wall holes. The degradation likely existed for a lengthy period of time (IMC 609, Appendix M, Table 4.1, Decision Attributes 4 and 6)

- These riser pipes were degraded to the point that the original design Code safety margins no longer existed to ensure that the pipe material remained within the elastic material property ranges. Because elastic material behavior under normal and accident loads was no longer assured, the team concluded, based on engineering judgment, that the SX riser pipes had an increased probability of rupture (IMC 609, Appendix M, Table 4.1, Decision Attributes 3, 5, and 8).

- The SX system is a risk significant system and while the frequency of a loss of the system is relatively low, the consequences are potentially high. Loss of SX cooling capability can affect almost all safety-related mitigating systems (IMC 609, Appendix M, Table 4.1, Decision Attribute 7)

- An SX riser pipe rupture may be mitigated by the configuration of the riser vault or by alternate strategies. However, these features were not specifically designed for these functions and so their success is uncertain (IMC 609, Appendix M, Table 4.1, Decision Attribute 7 and 8).

- A relatively large break is needed to overcome makeup sources and due to the large SXCT basin inventory (e.g. greater than 600,000 gallons), several hours would be available for corrective measures in the event of a large break (IMC 609, Appendix M, Table 4.1, Decision Attribute 8).

In parallel with NRC significance evaluations, the licensee completed a Phase 3 SDP evaluation as documented in BB PRA-017.75B, "Byron Essential Service Water (SX) Cooling Tower Riser Pipe Degradation Phase 3 Significance Determination Process (SDP) Assessment." The licensee concluded that the only challenge to riser integrity was beyond design basis seismic events; whereas the NRC concluded that an increase in the pipe rupture likelihood had occurred overall. The licensee used engineering judgment to assign probabilities of large pipe failure for varying levels of seismic hazards. Using this approach, a change in core damage frequency on the order of 3E-6/yr was estimated, which would result in no greater than a White condition under the SDP. In the final analysis, the NRC conclusion and the licensee conclusion regarding the risk significance were in agreement.

.9 Evaluate the adequacy and monitor implementation of licensee extent of condition plans. Confirm these plans include gathering information to support evaluating risk significance.

a. Inspection Scope

The team attended licensee meetings, interviewed plant personnel, observed maintenance activities, reviewed pertinent extent of condition issues for other safety-related components, and performed system walkdowns to assess the adequacy of the licensee's corrective actions for any potential extent-of-condition issues.

b. Findings and Observations

b.1 Initial Extent of Condition Activities

On October 26, 2007, the licensee's Plant Oversight Review Committee reviewed the SX system extent of condition plan in response to the 0C SX riser leak. The scope of systems evaluated by the licensee under this plan included the SX system, the circulating water system and minor portions of the condensate system, and the well water and primary water systems. Additionally, the fire protection system piping was reviewed but this review was limited to scoping only, and followup of fire protection piping issues was scheduled to occur as a post restart activity. Piping in sheltered environments such as the Turbine Building or Auxiliary Buildings was excluded. Based on this scoping review, 32 SX system areas were targeted for a walkdown inspection and review of outstanding corrective maintenance. Most of the SX components in these areas were located within enclosures such as vaults, and did not receive frequent inspections. As a result of these extent of condition walkdown inspections for the SX system, substantial degradation of the carbon steel bolts on 0SX138(A)B valves was identified and the licensee performed bolt replacement as a corrective action. The licensee also inspected portions of the buried SX pipe made accessible during excavation to install line stops. Based on licensee examinations of the pipe coatings and measurements of pipe wall thickness for these buried portions of SX pipe, no substantial degradation was identified.

The team noted that for most of the safety-related SX piping the licensee had taken credit for recent VT-2 inspections in areas which were not likely to be subject to external corrosion. The team questioned if the licensee credit for VT-2 visual examinations/walkdowns of the SX supply lines to the reactor containment fan coolers in 2006 and 2007 included portions of the SX supply lines behind cover plates which is connected to the cooling coils. The licensee stated that this area was in the scope of these visual examinations and no degradation was identified. To confirm this result, the team reviewed pictures taken of this area during the licensee's past VT-2 examinations and did not identify any substantial external pipe corrosion in this area. The scope of the licensee's extent of condition also included a walkdown of the risk significant non-safety related auxiliary feedwater suction supply piping and isolation valves located in vaults. No evidence of corrosion was found in this area. For the buried portions of the condensate storage tank supply pipe, the licensee credited the lack of any adverse condensate storage tank level trends to confirm the integrity of the buried condensate storage tank supply piping. Based on review of licensee actions completed prior to restart, the team concluded that the extent of condition was adequate to address the physical root cause of the SX riser degradation.

The licensee's initial extent of condition activities included removal, cleaning and storage of the degraded riser pipes in a quarantined area established inside an on-site warehouse. The licensee cleaned the exterior surface of the removed riser sections to bright metal by abrasive grit blasting. The licensee then performed UT and micrometer thickness measurements of the cleaned riser pipes in a grid pattern to obtain accurate measurements of SX riser pipe wall-loss in the as found condition (Attachment 3, Picture No. 6). The team concluded that these SX riser pipe wall measurements, were conducted appropriately, and provided information necessary to evaluate the risk significance for past plant operation with these degraded risers.

b.2 Failure to Identify Corroded 0SX138B Valve Bolting During VT-2 Examination

Introduction: The team identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the licensee's failure to identify severely corroded bolts (condition adverse to quality) on the 0B SX basin suction supply isolation valve 0SX138B.

Description: On November 2, 2007, the team identified that a licensee VT-2 inspector failed to identify severely corroded bolts on the 0B SX basin suction supply isolation valve 0SX138B as a condition adverse to quality.

On September 12, 2007, a licensee VT-2 inspector performed a visual examination of the SX piping components within the 0B SX basin vault which contained 0SX138B suction isolation valve for the B train of the SX system. This examination was required by the ASME Code and was intended to identify leakage or corrosion induced wastage of piping components caused by leakage. Based on this examination the VT-2 inspector did not identify system leakage or any other conditions adverse to quality. The team identified that this VT-2 inspector had failed to identify significant bolt corrosion on 0SX138B, which was subsequently identified on October 22, 2007, during the licensee's SX system extent of condition reviews. Specifically, during a walkdown of SX piping in the 0B SX basin vault, the licensee staff identified severely corroded bolting on the 0SX138B (reference AR 00687720). The extent of corrosion and wastage on the bolting prompted the licensee to replace 1/2 of the bolts on the lower half of this valve. The vault containing 0SX138B is located near the bottom elevation of the SX basin (e.g. many feet below grade level) and had on past occasions partially filled with water, which appeared to have contributed to the more extensive corrosion found on the fasteners located on the bottom 1/2 of this valve.

To evaluate the structural integrity of the 0SX138B bolts, the team observed and photographed the in-situ bolt condition prior to bolt replacement (Attachment 3, Picture No. 8). The team also observed the condition of the bolts following removal from the valve and after removal of rust deposits. The team applied the visual acceptance criteria for ASME Code Section XI, Category B-G-2, bolting (e.g. less than 2 inch diameter), which considers localized general corrosion that reduces the bolt or stud cross-sectional area by more than five percent a rejectable condition. The team estimated that the extent of corrosion had not reduced the cross sectional area below five percent for any of the removed bolts. Therefore, the team concluded that the corrosion induced wastage had not compromised the structural integrity of the 0SX138B valve bolting.

The 0SX138B bolt corrosion had developed over a period spanning many years and was present (but not identified), during the licensee's September 12, 2007, VT-2 examination. Based on interviews with the licensee's VT-2 inspector, the team attributed the failure to identify the degraded bolts to an inappropriately high threshold for recognizing a condition adverse to quality. The licensee entered this issue into the corrective action program (AR 00693502).

Analysis: The team determined that failure of the licensee's VT-2 inspector to identify severely corroded bolts on valve 0SX138B was a performance deficiency that warranted a significance evaluation.

The team determined the finding was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," because the finding was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Absent NRC intervention, the inappropriate threshold for identification of bolt corrosion as a condition adverse to quality would have gone uncorrected. The team determined that the isolation required for a postulated failure of the 0SX 138B valve bolting, would result in loss of one SX train in each Unit. Therefore, this finding, if uncorrected, could lead to undetected corrosion failures in carbon steel components affecting the reliability or capability of the SX system (e.g. effected the objective for the Mitigating Systems Cornerstone).

This finding was evaluated in accordance with IMC 0609.04, "Phase 1 – Initial Screening and Characterization of Findings." Under the Mitigating Systems Cornerstone Column of Table 4a, the team answered "No" to each screening question, because the corrosion of the 0SX 138B valve bolts had not yet affected structural integrity or operability of the system. Therefore, the finding screened as having very low safety significance (Green).

The cause of this finding was related to the Corrective Action Program Component (Item P.1(a) of IMC 305) for the cross-cutting area of Problem Identification and Resolution, because the licensee staff failed to adopt an appropriate threshold for identifying issues. Specifically, the failure of the licensee VT-2 examiner to identify these degraded bolts was related to an excessively high threshold for problem identification.

Enforcement: During an NRC inspection conducted between October 23, 2007, and February 14, 2008, a violation of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Actions,” was identified.

10 CFR 50, Appendix B, Criterion XVI, “Corrective Actions,” requires in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected.

Contrary to the above, on September 12, 2007, during performance of a VT-2 examination of SX piping components within the 0B SX basin vault which contained 0SX138B suction isolation valve and bolting, the licensee failed to promptly identify the severely corroded bolts on valve 0SX138B (condition adverse to quality). On October 22, 2007, the licensee identified and replaced these corroded fasteners. Because this finding was of very low safety significance and because the finding was entered into the licensee's corrective action program (reference AR 00693502), this violation is being treated as a non-cited violation (NCV 05000454/2007009-05; NCV 05000455/2007009-05) consistent with Section VI.A of the NRC Enforcement Policy.

4OA6 Meetings

Exit Meeting

On February 14, 2008, the team presented the inspection results to Mr. D. Hoots and members of the licensee staff. The team asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

Attachments:
1. Supplemental Information
2. Timeline of Events
3. Pictures of Degraded SX Components
4. Byron Special Inspection Charter
5. IMC 609 – Appendix M Table 4.1 (Preliminary)

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

D. Hoots, Site Vice President
B. Adams, Plant Manager
B. Noll, Vice President Exelon Mid-Atlantic Operations
S. Greenlee, Site Engineering Director
M. Prospero, Byron Operations Director
B. Perchiazzo, Senior Manager of Design – Byron
T. Hulbert, NRC Coop Regulatory Assurance
G. Contrady, Acting Nuclear Oversight Manager – Byron
B. Ledger, Byron Design Engineer
J. Edom, Byron Site Risk Management Engineer
A. Giancatarino, Engineering Director
W. Grundmann, Regulatory Assurance Manager

Nuclear Regulatory Commission

B. Bartlett, Senior Resident Inspector
R. Ng, Resident Inspector
J. Tsao, Piping and NDE Branch Division of Component Integrity, NRR
M. Hartzman, Mechanical and Civil Engineering Branch, NRR
C. Acosta; Inspector, Engineering Branch 2, Region III

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000454/2007009-01(DRS); 05000455/2007009-01(DRS)	NCV	Operating Experience Procedure Not Followed for Service Water Corrosion Event
05000454/2007009-02(DRS); 05000455/2007009-02(DRS)	AV	Failure to Implement Timely Corrective Actions for Degraded SX Riser Piping
05000454/2007009-03(DRS); 05000455/2007009-03(DRS)	AV	Inadequate Design Margins for Continued Operation of SX Riser Pipes
05000454/2007009-04(DRS); 05000455/2007009-04(DRS)	NCV	TRM Change Bypasses Procedure Change and Safety Evaluation Processes
05000454/2007009-05(DRS); 05000455/2007009-05(DRS)	NCV	Failure to Identify Corroded 0SX138B Valve Bolting During VT-2 Examination

Closed

05000454/2007009-01(DRS); 05000455/2007009-01(DRS)	NCV	Operating Experience Procedure Not Followed for Service Water Corrosion Event
05000454/2007009-04(DRS); 05000455/2007009-04(DRS)	NCV	TRM Change Bypasses Procedure Change and Safety Evaluation Processes
05000454/2007009-05(DRS); 05000455/2007009-05(DRS)	NCV	Failure to Identify Corroded 0SX138B Valve Bolting During VT-2 Examination

Discussed – None.

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the team reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

Calculations and Evaluations

BYR97-034; Essential Service Water Cooling Tower Basin Minimum Volume Versus Level and Minimum Usable volume Calculation dated February 21, 1997
NED-M-MSD-014; Byron Ultimate heat Sink Cooling Tower Basin Makeup Calculation; dated July 24, 2001
EC 366395; Nonconformance Evaluation for Line 0SX97AE-24" Near Valve 0SX163E; Revision 0
EC 367082; Operability Evaluation 07-008, UHS Capability With Loss of SX Fans Due to a Tornado; Revision 1 and Revision 0
EC 367754; OP EVAL 07-009, SXCT Riser Piping Below Minimum Wall Thickness; Revision 0
EC 367911; Evaluate 2 SXCT Fans Out of Service in Support of Restart from 2007 Dual Unit Shutdown; dated October 25, 2007
EC 367914; Dual Unit Outage SX Cell Mode 5 Requirements; dated October 21, 2007
EC 367922; Install Temporary Change to Cut and Blind Flange the 0C SX Bypass Line and Grout in Opening in SXCT wall; Revision 0
EC 367937; Temporary Support for 0D SX Riser Pipe Compensatory Action for Operability Assessment 07-009; Revisions 0. 1 and 2
EC 367967; Minimum Wall Thickness Calculation for Byron's SXCT Degraded Riser Piping Based on Structural Stability Consideration to Resist Local Buckling; Revisions 0 and 1
EC 367974; Determine Design Min Wall Thickness for SX Riser Line 0SX97AD-24"; Revision 0
EC 368389; Evaluation of Past Operability of the SXCT Risers; Revision 0
EC 366395; Minimum Wall Evaluation for Line 0SX97AE-24"; Revision 0
EC 368032; Temporary Support for 0D SX Riser Pipe; Revision 0
EC 382714; Planning Will Need Details on the Expected Repair of the Current SX Tower Leak Described in This Work Package; dated October 22, 2007
EC 368559; Inventory Loss from the SXCT Riser Vault; Revision 0.
EXLN-30Q-305; Operability Evaluation of Essential Service Water (SX) Cooling Water Risers, Byron Station; Revision 0
EXLN-30Q-302; Operability Evaluation of Essential Service Water (SX) Cooling Water Risers, Byron Station; Revision 1
EXLN-30Q-301; Operability Evaluation of Essential Service Water (SX) Cooling Water Risers, Byron Station; Revision 1
BB PRA-017.75B; Byron Essential Service Water (SX) Cooling Tower Riser Pipe Degradation Phase 3 Significance Determination Process (SDP) Assessment; Revision 1

Corrective Action Program Documents As a Result of NRC Inspection

AR 00689235; Watch Welder Work Without a Procedure; dated October 25, 2007
AR 00689577; 1/2BOA PRI-7 SX Malfunction Needs Enhancement; dated October 25, 2007
AR 00690002; NRC Identified Clarification Needed in Welding T&RM; dated October 26, 2007
AR 00690101; Deficiency Identified While Answering NRC Question; dated October 26, 2007
AR 00690311; NRC Observation of IR Threshold level for Corrosion Issues; dated October 27, 2007

AR 00690315; NRC Identified Discrepancy in EC for TCCP; dated October 27, 2007
AR 00690392; NRC Identified Deficiency in EC 367922; dated October 27, 2007
AR 00690398; NRC Identified Discrepancy in UHS Operability Calculation; dated October 27, 2007
AR 00691059; NRC Question on Surface Examination Lighting Requirements; dated October 29, 2007
AR 00691325; Initial SXCT Op Evaluation did not Consider Buckling; dated October 29, 2007
AR 00691349; EC 367974 Did not Properly Consider Functional Capability; dated October 29, 2007
AR 00692030; Error Made on Temporary Support Design EC # 368032; dated October 30, 2007
AR 00692498; TRM Revision 54 Deficient; dated October 31, 2007
AR 00693484; NRC Potential NCVs on SX Riser Piping; dated November 2, 2007
AR 00693502; Potential NCV of 10 CFR Appendix B Criterion XVI 0SX138B; dated November 2, 2007
AR 00696006; Concerns with Past Issue Resolution on OF, OG, OH SX Risers; dated November 7, 2007
AR 00696303; NRC Identified Weakness in VT-2 and System Engineering Train; dated November 8, 2007
AR 00696417; EC 366295 did not Consider Thermal Functional Capability; dated November 8, 2007
AR 00696519; Missed Opportunity during Operating Experience Review – External Corrosion; dated November 8, 2007

Corrective Action Program Documents

PIF 454-201-96-1067 0A SX Makeup Pp Auto Started during Performance of 0B SX Makeup Pp Monthly Surveillance; dated May 25, 1996
PIF B1997-00908; 0C SXCT Bypass Line; March 10, 1997
AR 00157899; Found Cracks and Holes in Conduit with a Faulty Ground; May 8, 2003
AR 00220607; Corrosion Product Buildup on 0SX163G Flange Bolting; May 12, 2004
AR 00319146; 0BOL 7.9 Requires Additional Guidance during Tornados; dated March 30, 2005
AR 00451041; Vent Barrier Requirements Not Met on PBI 05-326; dated February 7, 2006
AR 00507187; Through Wall Leak in SX Piping; dated July 7, 2006
AR 00517974; 0G SXCT Cell Inspection Results – Overall Condition; August 8, 2006
AR 00517987; 0G SXCT Cell Inspection Results – 0SX163G Valve Studs/Nuts; August 8, 2006
AR 00517988; 0G SXCT Cell Inspection Results – 0SX163G MOV Conduit; August 8, 2006
AR 00544085; Clean/Coat the SX M/U Line Vacuum Breaker in Vault 5; dated October 14, 2006
AR 00544087; Clean/Coat the SX M/U Line Vacuum Breaker Pipe in Vault 6; dated October 14, 2006
AR 00544803; 0D SXCT Cell Inspection Results Overall Condition; dated October 16, 2006
AR 00544804; 0D SXCT Cell Inspection Results – Coat Pipe Below 0SX163D; October 16, 2006
AR 00563907; 2006 0B SXCT Cell Inspection Results Overall Documentation; dated November 30, 2006
AR 00563914; 2006 0B SXCT Inspection Riser Valve Pipe Corrosion; dated November 30, 2006
AR 00599643; 0C SXCT Cell Inspection 2007 Riser Valve Piping Needs Coated; dated March 5, 2007
AR 00630679; 0A SXCT Cell Inspection 2007 Riser Valve Piping Needs Coated; dated May 17, 2007
AR 00636745; 0H SXCT Riser Valve Piping Needs to be Cleaned and Coated; June 4, 2006

AR 00637335; Generate WO to Perform Pipe Cleanup and UT; dated June 5, 2007
AR 00640621; Corrosion on 0E SXCT Cell Riser Valve Studs & Nuts; June 14, 2007
AR 00640363; UT Thickness Results of 0SX163E Lower Flange; dated June 14, 2007
AR 00646604; Need WR to Perform UT Exam – Upstream of 0SX163B; July 2, 2007
AR 00646607; Need WR to Perform UT Exam – Upstream of 0SX163C; July 2, 2007
AR 00646608; Need WR to Perform UT Exam – Upstream of 0SX163D; July 2, 2007
AR 00646609; Need WR to Perform UT Exam – Upstream of 0SX163F; July 2, 2007
AR 00646610; Need WR to Perform UT Exam – Upstream of 0SX163G; July 2, 2007
AR 00646612; Need WR to Perform UT Exam – Upstream of 0SX163H; July 2, 2007
AR 00646897; NDE (UT) SX Riser Piping 0SX97AE-24"; July 3, 2007
AR 00651272; Replace Piping – Pending Results of UT Exam; July 18, 2007
AR 00651274; Replace Piping – Pending Results of UT Exam; July 18, 2007
AR 00651277; Replace Piping – Pending Results of UT Exam; July 18, 2007
AR 00651284; Replace Piping – Pending Results of UT Exam; July 18, 2007
AR 00651280; Replace Piping – Pending the Results of UT Exam; July 18, 2007
AR 00651289; Replace Piping – Pending Results of UT Exam; July 18, 2007
AR 00651293; Replace Piping – Pending Results of UT Exam; July 18, 2007
AR 00651296; Replace Piping – Pending the Results of UT Exam; July 18, 2007
AR 00657748; UT Thickness Results on 0B SX Piping in the RSH Below 87.5 percent; August 6, 2007
AR 00676679; 0SX163D Vault Leaking Approx. 1 GPM to Ground; September 27, 2007
AR 00677307; NOS ID Inadequate Operability Determination; September 28, 2007
AR 00682786; UT Thickness Results of 0SX163H Lower Flange Line 0SX97AH-24; dated October 10, 2007
AR 00685955; Min Wall on SX Riser Piping 0SX97AB-24; dated October 17, 2007
AR 00686355; Verify SX Riser Valve Compartment Weep Holes are Not Blocked; dated October 18, 2007
AR 00687024; Through Wall Leak on Riser Piping Upstream of Valve 0SX163C; dated October 19, 2007
AR 00687042; Departure from TLCO 3.4.F Condition B Action Statement; dated October 19, 2007
AR 00687165; Severely Corroded Studs and Nuts on Valve 0SX163F; October 20, 2007
AR 00687201; WR to replace Studs and Nuts on 0SX163B; October 20, 2007
AR 00687720; 0B SXCT Suction Valve 0SX138B Bolting Degraded; dated October 22, 2007
AR 00689440; Water Coming into Contact of in Process Welds on SX Piping; dated October 25, 2007
AR 00690882; NDE Results on 0 SX Risers; dated October 29, 2007
AR 00690943; Management Request Past Operability Review of SXCT Risers; dated October 29, 2007
AR 00691154; 0A and 0D Riser Piping Inoperable; dated October 30, 2007
AR 00696316; No Procedure for Past Operability Guidance; dated November 8, 2007

Drawings

M-900 Sh. 8; Outdoor Piping Essential Service Water at Cooling Tower; Revision AD
M-42 Sh. 1A; Diagram of Essential Service Water; Revision AM
M-42 Sh. 1B; Diagram of Essential Service Water; Revision AN
M-42 Sh. 2A; Diagram of Essential Service Water; Revision AU
M-42 Sh. 2B; Diagram of Essential Service Water; Revision AV
M-42 Sh. 3; Diagram of Essential Service Water; Revision AZ
M-42 Sh. 4; Diagram of Essential Service Water; Revision AN

M-42 Sh. 5A; Diagram of Essential Service Water; Revision AD
M-42 Sh. 5B; Diagram of Essential Service Water; Revision AD
M-42 Sh. 6; Diagram of Essential Service Water; Revision AW
M-42 Sh. 7; Diagram of Essential Service Water; Revision AE
M-42 Sh. 8; Diagram of Essential Service Water; Revision 0
M-126 Sh. 1; Diagram of Essential Service Water; Revision AZ
M-126 Sh. 2; Diagram of Essential Service Water; Revision AD
M-126 Sh. 3; Diagram of Essential Service Water; Revision AE
6E-1-4030 AF04; Schematic Diagram AF Pp 1A & 1B SX Suction Valves 1AF006A & B; Revision R
6E-1-4030 AF11; Schematic Diagram AF Pp 1A & 1B SX Suction Valves 1AF017A & B; Revision M

<u>Other Documents</u>

Byron News Flash; Update on SX Riser Piping Inspections; dated October 18, 2007.
BB PRA-017.75B; Byron Essential Service Water (SX) Cooling Tower Riser Pipe Degradation Phase 3 Significance Determination Process (SDP) Assessment; Revision 1
BYR-71886; Evaluation of Corrosion of Byron SX Cooling Tower Risers; dated November 16, 2007
Root Cause Report; Through Wall Pipe Leak on the 0C SX Riser Piping Upstream of the 0SX163C; dated December 12, 2007
0SX163E Riser Caliper Readings; dated October 31, 2007
Proposed Test Plan for Lab Evaluation of Byron C SX Pipe Spool Piece; dated November 1, 2007
Memorandum from D. Hoots to All Byron Station Employees; Subject Procedure Adherence; dated October 26, 2007
Report Number 2007-589; F Cell Caliper Readings; not dated.
Report Number 2007-587; G Cell Caliper Readings; not dated.
Root Cause Investigation Charter; Revision 6.
Operability Determination No. 01-012 0B ESWCT Basin Leaking; dated December 13, 2002
Letter to D.B. Wozniak; Evaluation of SX Cooling tower Distribution Piping; March 28, 1990
Letter to D.B. Wozniak; Byron Station Units 1 and 2, SX Replacement Piping Study; April 5, 1990
Letter to J.R. Vanlaere; Byron Units 1 & 2 Modification DCP # 9303506 (M6-0-93-012) Essential Service Water Cooling Tower Piping Replacement; December 16, 1996
Letter to NRC; Request for Temporary Relief from ASME Section III Requirements – Use of Line Stopping Equipment on Essential Service Water ASME Class 3 Piping; April 11, 1997
Letter to D.B. Wozniak; Byron Station Unit 1 and 2 Essential Service Water Cooling Tower Pipe Replacement Minor Change Approval Minor Change #MCR6-0-90-633; June 26, 1990
Byron Station Operational Logs dated October 19, 2007 through October 22, 2007.
Clearance Order; B SX Basin OOS for Riser Piping Work Window; dated October 21, 2007
2005 AFI ER.3-1; Raw Water Improvement Plan; dated October 25, 2007
TRM Change; Revise TRM Section 1.5 TLCO and TSR Implementation Sections, Request 07-015; dated October 27, 2007

<u>Modification</u>

BYR-000546M; M6-0-93-012, Mod to Replace Carbon Steel Piping With Stainless Steel; 11/17/95

Procedures

AD-AA-101; Processing of Procedures and T&RMs; Revision 18
BAP 1310-10; HU-AA-104-101 Procedure Use and Adherence Byron Addendum; Revision 9
BAR 0-37-A8; SX CLG TWR Basin Level High / Low; Revision 8
BAR 0-37-B7; SX Makeup Pmp Auto; Revision 7
0BOA PRI-7; Loss of Ultimate Heat Sink Unit 0; Revision 0
1BOA PRI-7; Essential Service Water Malfunction Unit 1; Revision 103
BOP SX-12; Makeup to Essential Service Water Mechanical Draft Cooling Tower Basin; Revision 8
1BVSR 4.f.2-5: Scheduled Visual Examination (VT-2) of Class 2 Components at Nominal Operating Pressures; Revision 1
ER-AA-335-003; Magnetic Particle Examination; Revision 3
ER-AA-335-004; Manual Ultrasonic Measurement of Material Thickness and Interfering Conditions; Revision 2
ER-AA-2030; Attachment 4; System Walkdown Standards; Revision 5
ER-AA-335-1002; Nondestructive Examination Training; Revision 1
ER-AA-335-015; VT-2 Visual Examination; Revision 6
HU-AA-104-101; Procedure Use and Adherence; Revision 3
LS-AA-115; Operating Experience Procedure; Revision 1
0BVSR z.7.a.3; Unit 0 Deep Well Pp Makeup Flow Verification; Revision 2
OBVSRz.7.a.5; Essential Service Water Cooling Tower Inspection; Revision 3
0BwOA PRI-8; Auxiliary Building Flooding Unit 0 (Braidwood); Revision 2
OP-AA-108-115; Operability Determinations; Revision 4
OU-AP-104; Shutdown Safety Management Program Byron Braidwood Annex; Revision 9
Special Process Procedures Manual Nondestructive Examination; Magnetic Particle Examination NDT-B; Revision 19
TRM 3.4.f; Structural Integrity; Revision 39
TRM 1.5; TLCO and TSR Implementation; Revision 39
TRM 1.3; Completion Times; Revision 39
TQ-AA-122; Qualification and Certification of Nondestructive Personnel; Revision 3

Ultrasonic Thickness Calibration Data Sheets

2SX01-BA-36; Pipe Near 2SX 001A; dated October 28, 2007
1SX01-BA-36; Pipe Near 1SX 001A; dated October 28, 2007
0SX01-AA-48; Upsteam of 0SX 0013A; dated October 22, 2007
0SX97-AB-24; Hot Top; dated October 27, 2007
0SX97-AA-24; A Riser Pipe; dated October 19, 2007
0SX97-AA-24; A Riser Pipe; dated October 27, 2007
0SX97-AA-24; A Riser Pipe; dated October 28, 2007
0SX97-AB-24; B Riser Pipe; dated October 17, 2007
0SX97-AB-24; B Riser Pipe; dated November 1, 2007
0SX97-AC-24; C Riser Pipe; dated October 27, 2007
0SX97-AD-24; D Riser Pipe; dated October 27, 2007
0SX97-AD-24; D Riser Pipe and C Bypass Line; dated October 20, 2007
0SX97-AE-24; E Riser Pipe; dated June 14, 2007
0SX97-AE-24; E Riser Pipe; dated October 20, 2007
0SX97-AF-24; F Riser Pipe; dated October 20, 2007
0SX97-AF-24; F Riser Pipe; dated October 25, 2007
0SX97-AG-24; G Riser Pipe; dated October 20, 2007

0SX97-AG-24; G Riser Pipe; dated October 27, 2007
0SX97-AH-24; H Riser Pipe; dated October 10, 2007
0SX97-AB-24; B SX Riser Cut Line; dated October 28, 2007
0SX97-AB-24; B SX Riser Cut Line; dated October 29, 2007
0SX97-AE-24; E SX Riser Cut Line; dated October 27, 2007
0SX97-AF-24; F SX Riser Cut Line; dated October 27, 2007
0SX97-AG-24; G SX Riser Cut Line; dated October 26, 2007
0SX97-AH-24; H SX Riser Cut Line; dated October 23, 2007
0SX 97-AA-24; SX A Pipe at Line Stop Pipe Location October 27, 2007
0SX 97-AC-24; SX C Pipe at Line Stop Pipe Location October 26, 2007
0SX 97-AD-24; SX D Pipe at Line Stop Pipe Location October 27, 2007

Welding Documents

CC-AA-501-1021; Exelon Nuclear Welding Program Repair of Welds and Base Metal; Revision 1
CC-AA-501-1003; Exelon Nuclear Welding Program Visual Weld Acceptance Criteria; Revision 1
WPS 1-1-GTSM-PWHT: ASME Welding Procedure Specification Record (QW-482); Revision 1
A-001; Clinton Power Station Procedure Qualification Record ASME Section IX; October 19, 1998
A-002; Clinton Power Station Procedure Qualification Record ASME Section IX; March 9, 1999
A-002; Clinton Power Station Procedure Qualification Record ASME Section IX; January 3, 1984

Work Orders

WO 882878-01; SEP VT-2 Paper Close U1 Trn B SX Pump Suction Subsyst1SX-3-2; January 4, 2007
WO 1073655-1; “A” Bolt Tightening Sequence – 44 Bolts; Revision 0
WO 1073589-1; “A” Bolt Tightening Sequence – 44 Bolts; Revision 0
WO 868179-01; SEP VT-2 Paper Close U1 Trn A SX Pump Suction Subsyst1SX-3-1; January 4, 2007
WO 99152503-01; Scheduled Visual Examination (VT-2); August 9, 2001
WO 99155784-01; Scheduled Visual Examination (VT-2); August 9, 2001
WO 526218-01; Unit 1 (SX-3-6) ASME Section XI Pressure Test (Class 2 and 3); June 25, 2004
WO 526219-01; Unit 1 (SX-3-5) ASME Section XI Pressure Test (Class 2 and 3); June 25, 2004
WO 850761-01; Unit 1 (SX-3-5) ASME Section XI Pressure Test (Class 2 and 3); January 4, 2007
WO 850762-01; Unit 1 (SX-3-6) ASME Section XI Pressure Test (Class 2 and 3); May 30, 2007
WO 983110-01; 2006 0B SXCT Inspection – Riser Valve Pipe Corrosion #10; October 24, 2007
WO 970118040-01; Scheduled Visual Examination (VT-2) of Class 2 & 3 Component; January 30, 2000
WO 970116092-01; Scheduled Visual Examination (VT-2) of Class 2 & 3 Component; June 9, 1999
WO 1007521-01; 0C SXCT Cell Inspection 2007: Riser Valve Piping Needs Coated; October 24, 2007

LIST OF ACRONYMS USED

AR	Action Request
ASME	American Society for Mechanical Engineers
CCDP	Condition Core Damage Probability
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
gpm	Gallons per Minute
IMC	Inspection Manual Chapter
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
NCV	Non-Cited Violation
NRC	United States Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
PHC	Plant Health Committee
psi	Pounds per Square Inch
RCP	Reactor Coolant Pump
RCT	Root Cause Team
SDP	Significance Determination Process
SX	Essential Service Water
SXCT	Essential Service Water Cooling Towers
TRM	Technical Requirements Manual
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
UT	Ultrasonic Examination

TIMELINE OF EVENTS - SX RISER PIPE DEGRADATION

Date	Event and Licensee Actions
3/28/90	ComEd's SMAD letter to Mr. D. B. Wozniak dated March 28, 1990, Subject: "Evaluation of SX Cooling Tower (SXCT) Distributions Piping." letter discussed the degraded condition of the piping at the SXCT. The corroded pipe conditions were attributed to the failure of the protective coating on the piping. SXCT piping was originally coated with 2.0 mils of red lead based coating. Specifically, the letter stated that, "All piping examined showed extensive surface corrosion which consisted of loose scaly rust. The rust scale was easily dislodged and removed under finger pressure and delaminated as large pieces with the same relative curvature of the pipes."
4/5/90	Sargent & Lundy (S&L) Engineers (letter to Mr. D. B. Wozniak, dated April 5, 1990) conducted study of the SWXT piping for corrosion. This letter referenced the ComEd letter dated March 28, 1990. The results of the S&L study indicate that the piping was corroding more rapidly than the design specification called for. Corrosion rates documented in the letter were estimated to be, 5-10 mils per year external, and 2-10 mils per year internal (when system not operating) and 2-6 mils per year with system operating.
5/11/90	Certification of EC 65075 (Project No. 8653-79/80) Modification to replace SX cooling tower (header) piping. The ECN provided details associated with the replacement of existing carbon steel SWXT distribution piping with stainless steel.
6/26/90	Nuclear Engineering Department letter to Mr. D. B. Wozniak, dated June 26, 1990, Subject: "Byron Station Unit 1 and 2 Essential Service Water Cooling Tower Pipe Replacement Minor Change Approval Minor Change #MCR6-0-90-633." This letter described minor change to replace the carbon steel SWXT spray piping with stainless steel to provide a material which is more resistant to corrosion.
5/19/93	Work Order (WO) 93015271 through WO 93015278 issued to "clean and coat the riser piping between the concrete floor of the valve compartment and the riser valve."
6/3/93	Minutes from May 13, 2003, SX Riser Valve Task Force Meeting. Identified that Nuclear Work Requests (NWRs) were written to "clean and coat" the riser piping between the concrete floor of the valve compartment and the riser valve. Minutes indicate that this portion of piping would not be replaced under the piping replacement modification.
6/20/94	Plant Engineer walkdown of the SXCT was completed, including entry into each of the eight SX163 valve enclosure vaults (performed as part of MOD M6-0-93-012).
11/17/94	Modification M6-0-93-012 issued to replace SXCT pipe and drain piping including installation of permanent line-stop fittings upstream of each riser isolation valve. Note that this modification included replacement of corroded carbon steel SX piping with stainless steel.

TIMELINE OF EVENTS - SX RISER PIPE DEGRADATION

4/26/95 An engineer cancelled WO 93015271 through WO 93015278 to clean and coat the riser piping between the concrete floor of the valve compartment and the riser valve. The reason given was that, the valve and piping for the eight SX risers was going to be replaced during a modification planned for 1996.

12/16/96 Letter to Mr. J. R. Vanlaere (Byron System Engineering Supervisor) regarding Modification M6-0-93-012 (DCP #9303506). Modification Description included replacement of the existing safety-related 24 inch diameter carbon steel SXCT riser piping with type 316 stainless steel, to provide a material which is more metallurgically resistant to corrosion resulting from the environment at the cooling towers.

3/20/97 Issued PIF 97-0908; which identified that a section of piping inside the "D" riser valve enclosure is heavily corroded Minimum wall thickness requirement documented as 0.100 inch. Plant engineering staff identified this condition while walking down 0SX-163D for modification M6-0-93-012 (DCP #9303506). Pipe wall measurements recorded ranged from 0.32" to 0.40". Nominal wall thickness was 0.375 inch and the minimum wall thickness was determined to be 0.100 inch.

Actions:

- Accept as is, determined that an operability evaluation was not needed since measured pipe wall thickness was greater than 0.100 inch, and no formal calculation was completed.
- From the fall of 1997 through the spring of 1998 the licensee replaced all riser valves and downstream piping with stainless steel (Note: this did not include replacement of the riser pipe flange and upstream carbon steel riser piping).

4/11/97 Letter issued to the NRC, "Request for Temporary Relief from ASME Section III Requirements Use of Line Stopping Equipment on Essential Service Water ASME Class 3 Piping." In this letter, the licensee states that "Installation of cooling tower stainless steel riser piping and refurbishment of the riser isolation valves will provide significant improvement in the material condition of the safety-related SX cooling tower at Byron Station." and "The piping replacements are planned because Byron Station has determined that the minimum remaining life for the carbon steel riser piping is approximately five years."

6/2/99 Completed ASME Code Section XI required VT-2 inspection of "B" Basin; reference WO 970118040-01. This included inspection of SX risers "E"-"H".

No degradation identified.

6/11/99 Completed ASME Code Section XI required VT-2 inspection of "A" Basin; reference WO 970116092-01. This included inspection of SX risers "A"-"D".

No degradation identified.

TIMELINE OF EVENTS - SX RISER PIPE DEGRADATION

8/23/99	Picture of 0SX163C riser area shows small portion of riser pipe and flange area with generally adherent corrosion products.
10/11/01	Completed ASME Code Section XI required VT-2 inspection of “A” Basin reference WO 99155784-01. This included inspection of SX risers “A”-“D”. No degradation identified.
10/17/01	Completed ASME Code Section XI required VT-2 inspection of “B” Basin reference WO 99152503-01. This included inspection of SX risers “E”-“H”. No degradation identified.
2003	Picture of 0F SX riser pipe. Area below flange and around pipe appears corroded with loose scale and debris near riser pipe. No SX riser degradation identified in corrective action system associated with this picture.
5/8/03	Motor operated valve (MOV) rigid conduit at floor of riser vault 0SX-163F, approximately one foot from riser, found to be “severely corroded.” (AR 157899) In AR 157899, the licensee states that “It is expected that all of the SX riser valve enclosures will have similar degradation of the conduit. The other valves are already scheduled to be inspected as part of pre-defines utilizing OBSHR MOV-1.” Actions: • Licensee documented, “the conduit and exposed cables were examined and it was determined that the cables were unaffected by the corrosion... the condition is acceptable and the valve is considered operable.” • Recommended that “engineering should be assigned an action to provide a modification that contains generic details to allow repairs in the future as the riser valve enclosures are opened.”
5/12/04	In AR 220607, licensee states that “During Plant Engineering Department (PED) inspection inside the SXCT 0G riser valve enclosure a buildup of corrosion products was observed on the flange bolting, especially the upper nuts. The buildup flakes off fairly easily in large pieces exposing the bolting base metal. The lower flange, riser valve body, and bolting are all carbon steel, while the upper flange and riser piping are stainless steel.” And. “PED contacted engineering response team and engineering programs to independently inspect the condition.” And... “both the corrosion engineer and a bolting engineer inspected this issue with the PED engineer. They concurred that there was no degradation of the bolting or the riser valve components and the SXCT components remain within the structural capabilities of the original design.” And “no further corrective action is required.” Licensee appeared to base decision on corrosion sample sent to PowerLabs. The results of the PowerLabs report (BYR-13718) stated that “Since the scale deposits do not appear to be detrimental to the underlying base metal, no preventative action is considered necessary.”

TIMELINE OF EVENTS - SX RISER PIPE DEGRADATION

7/12/04 Completed ASME Code Section XI required VT-2 inspection of "B" Basin; reference WO 526219-01. This included inspection of SX risers "E"-"H".

No degradation identified.

8/20/04 Completed ASME Code Section XI required VT-2 inspection of "A" Basin; reference WO 526219-01. This included inspection of SX risers "A"-"D".

No degradation identified.

11/7/05 SX System Manager turn-over from M. Robinson to D. Bohnert.

No documentation in the "System Diary of Significant Events" noted during system turnover related to SX riser pipe corrosion.

5/23/06 Completed ASME Code Section XI required VT-2 inspection of 0SX-163C vault, WO 850761-01, which included inspection of riser 0C SX riser pipe. No ARs issued.

No degradation identified, no actions taken.

8/8/06 Completed ASME Code Section XI required VT-2 inspection of 0SX-163G vault, WO 850762-01, which included inspection of riser 0G SX riser pipe. "The 0SX163G riser valve/nuts are corroded. At present this appears to be surface corrosion with minor blooming starting." (AR 517974, AR 517987). Also completed 0G SXCT inspection under WO 812266-01.

Action: Recommended a WO to address repair at a future convenient opportunity.

8/8/06 MOV rigid conduit on floor of riser vault 0SX-163G, approximately one foot from riser, found to be corroded, described as "bubbling/blooming" in AR 517988.

Action: Recommended a "WO to address repair at future convenient opportunity."

10/16/06 Completed ASME Code Section XI required VT-2 inspection of 0SX-163D vault, WO 850761-01, which included inspection of riser "0D" SX riser pipe. Also completed SXCT cell inspection under WO 869593-01, which included inspection of 0D SX riser pipe. Examiner stated in the AR that "The 0SX163D riser valve piping between the concrete floor and the valve is corroding": (AR 544803).

Actions:

- Recommended a WO to "clean and coat" the pipe in a future work window (1-3 years recommended).
- Additional AR to be issued based on AR 544804 to create WO requested.
- WO 972007 at active status, scheduled for October 22, 2007.

TIMELINE OF EVENTS - SX RISER PIPE DEGRADATION

10/16/06 MOV rigid conduit on floor of riser vault 0SX-163D, approximately one foot from riser, found to be corroded, described as "bubbling/blooming" in AR 517988.

Action: Recommended "WO to address repair at next work window opportunity."

11/2/06 Byron staff learns of industry events associated with "Degradation of Essential Service Water Piping." An event which was most applicable to the SX riser piping degradation at Byron occurred in a service water line at a foreign nuclear plant. Specifically, there was a failure on the surface of a metal access port due to external corrosion. The failure mechanism was very similar to the corrosion that was found on a number of SX lines and that resulted in a leak developing on the "0C" SX riser pipe.

11/30/06 Completed PED cell inspection of 0SX-163B vault, WO 861952-01, which included inspection of risers "0B" SX riser pipe. Licensee identified that "in the riser valve vault, the 4 inches of carbon steel piping between the concrete floor and valve 0SX163B is showing sign of corrosion and needs to be cleaned and coated." (AR 563907, AR 563914, WR 226131).

AR 563907, also noted in Item 11, that the "riser valve 0SXA63B studs and nuts are corroding and need to be cleaned /coated or replaced.

Actions:

- Recommended cleaning and coating. (No actions completed as of 10/21/07).
- Future IR to generate WO for cleaning and coating.
- WO 983110 at Plan Status

11/30/06 MOV rigid conduit on floor of riser vault 0SX-163BG, approximately one foot from riser found to be "corroded and needs repair" (AR 563907)

Action: Recommended "WO to address repair at future convenient opportunity."

3/5/07 Completed inspection of 0SX-163C vault for cell fan assembly work, (WO863598) which included inspection of risers "0C" SX riser pipe. "It was identified the exposed carbon steel pipe upstream from riser valve 0SX163C had degraded since the inspection last May. There is corrosion product flaking off from the pipe. Last year no loosed flaking was observed lying around the pipe." (AR 599643, WR 233495)

Action: Recommended WO to clean pipe and apply a protective coating. (No actions completed as of 10/21/07).

3/15/07 SX System Manager position turn-over from Mr. Bohnert to Mr. Welt.

No documentation in the "System Diary of Significant Events" noted during system turnover related to SX riser pipe corrosion.

TIMELINE OF EVENTS - SX RISER PIPE DEGRADATION

3/29/07 SX System Engineer completed evaluation of the previous industry events regarding "Degradation of Essential Service Water Piping" for applicability to Byron Station.

Action: Based on this review, no additional actions were identified for the Byron Station. Specifically, the licensee concluded that implementation of the Raw Water Program and periodic visual examinations were adequate to address this issue.

5/4/07 Completed ASME Code Section XI required VT-2 inspection of 0SX-163F vault, WO 850762-01, which included inspection of riser "0F" SX riser pipe.

No degradation identified.

5/17/07 Completed ASME Code Section XI required VT-2 inspection of 0SX-163A vault, WO 850761-01, which included inspection of riser "0A" SX riser pipe. Licensee stated "Approximately 4" of exposed carbon steel pipe upstream from riser valve 0SX163A has had the protective coating degrade to the point that there is some flaking of the carbon steel pipe.": (AR 630679) AR 630679 states that "this condition exists at all of the riser valves." Specifically states that "degradations at "B" and "C" cells at similar locations...shows surface rusting/flaking."

AR 630679 also contains a discussion of why potential wall thinning of the riser pipe is not a concern. Specifically, the licensee states that "based on the above, the degradation of piping due to external rusting/flecking is not expected to be at a point that would have reduced the wall thickness from its original thickness of 0.375" down to 0.153", and therefore, there should not be an immediate concern with structural integrity and pressure boundary for the piping system......the external degradation due to rusting/flecking are not expected severe enough that would affect the section properties in a drastic manner and therefore, the safety related function of the piping system would not be compromised."

Actions:

- Recommended "the carbon steel be cleaned up and have a protective coating applied during the next available work window." (No actions completed as of 10/21/07).
- Recommended "UT at the similar location for the "E" cell, which will be in the next work window between 6/4/07 and 6/21/07 (AR 637335 generated to create W/O to perform UT on 6/14/07. WO 242191, created to perform clean up and UT of the "0E" SX riser pipe, states that "pipe UT will have to determine pipe needs to be replaced during the work window before declaring the "OE" SX Cell operable."

05/31/07 Completed ASME Code Section XI required VT-2 inspection of 0SX-163B vault, WO 850761-01, which included inspection of riser "0B" SX riser pipe. AR 630679 states that "degradation at "B" shows surface rusting/flecking."

06/04/07 Completed ASME Code Section XI required VT-2 inspection of 0SX-163H vault, WO 850762-07, which included inspection of riser "0H" SX riser pipe. "It was identified that exposed carbon steel pipe upstream from riser valve 0SX163H has had the protective coating degraded, exposing the carbon steel pipe." (AR 636745)

Action: Recommended a WO to clean pipe and apply protective coating at a future convenient opportunity. Close to WR 242062 (No actions completed as of 10/21/07).

6/05/07 UT exam to be scheduled for "E" riser pipe. AR 637335 (see May 15, 2007 when "A" degradation noted.): States" IR 630679 had identified rusting/flaking of piping below the riser valve 0SX163A. This kind of degradation is found in all other cells also. AR 637335 was written to identify the "need to cleanup the area to perform UT to determine thickness of piping below the riser valve 0SX163E at the "E" cell which is in its work window. The pipe cleanup and UT will be done at the same time." Work to be performed on 6/14/07 when "E" is scheduled for a VT-2 visual examination.

6/14/07 Completed ASME Code Section XI required VT-2 inspection of 0SX-163E vault, WO 850762-01, which included inspection of risers "0E" SX riser pipe. Licensee identified that "riser valve studs have a good deal of corrosion on them "(AR 640621).

Action: The station ownership committee (SOC) comments stated "valve vault inspections are a surveillance activity, so there is no action needed to evaluate the extent of condition to the other riser valves." This comment was made even though ARs had been written to look at the riser pipe in all of the vaults.

6/14/07 The licensee documented in UT report No. 2007-382 and AR 00640363, the 0E SX riser pipe wall thickness measured at two areas on the pipe perimeter 180 degrees apart. The minimum pipe wall thickness recorded at these two locations was 0.124 inch and 0.122 inch respectively.

6/25/07 Presentation by SX System Engineer to PHC regarding new focus area; of "Piping Wall Thinning." Presented results of June 14, 2007 "E" riser UT examination.

Action: PHC minutes stated "Rapid Response is preparing EC366395 due 7/11/07. The result is to include minimum acceptable wall criteria, and it will specify follow-up actions for additional UT and pipe replacement." (EC 366395 decreased acceptable wall thickness to 0.121" so that no action was necessary).

7/2/07 PHC meeting. Minutes noted System Engineer created 7 ARs (from AR 640363-03) to perform UT exams on SX riser piping upstream of the riser valves in October 2007(see AR numbers below):

0SX163A(AR646601/WO1043950) 0SX163E – N/A
0SX163B(AR646604/WO1043953) 0SX163F(AR646609/WO1043957)
0SX163C(AR646607/WO1043954) 0SX163G(AR646610/WO1043960)
0SX163D(AR646608/WO1043956) 0SX163H(AR646612/WO1043965)

TIMELINE OF EVENTS - SX RISER PIPE DEGRADATION

7/11/07	The licensee documented in AR 00640363-02, the application of EC 366395 "Nonconformance Evaluation for Line 0SX97AE-24" Near Valve 0SX163E" to the "E" riser wall thickness and accepted this riser pipe "use-as-is." In EC 366395, the licensee established a minimum design pipe wall thickness of 0.121 inch applicable to the 24 inch diameter SX riser pipes.
7/16/07	Plant Health Committee added SX riser pipe degradation to top 5 SX issues list. PHC minutes stated that 8 AR's are to be created to generate 8 WO's, 2 of which will be used as piping repair/replacement placeholders in late-2007/early-2008.
7/18/07	8 AR's and 8 WO's are created for SX piping repair replacement as a result of 7/16/07 PHC meeting recommendations. 0SX163A(AR651272/WO1047832) 0SX163E(AR651284/WO1047836) 0SX163B(AR651274/WO1047833) 0SX163F(AR651289/WO1047837) 0SX163C(AR651277/WO1047834) 0SX163G(AR651293/WO1047838) 0SX163D(AR651280/WO1047835) 0SX163H(AR651296/WO1047839)
8/6/07	PHC Meeting minutes. Action: System Engineer to review feasibility of exterior coating for riser piping or if carbon steel is replaced with stainless steel, then the cost is not justified.
9/5/07	Plant Review Committee approves funds for riser valves repairs (System Engineer recommended repair/replace 2 riser valves and lines per year starting 2008 and completing in 2011. Approval of riser pipe replacement contingent on receipt of additional information from System Engineer, including technical alternatives and other technical work).
9/12/07	Completed ASME Code Section XI required VT-2 inspection of piping in "0SX138B" vault. Reference WO 882878-01 (No indications identified). No degradation identified, no actions taken.
9/28/07	"D" Vault opened and inspected, for increased leakage but no through wall leak detected. (AR 676679/AR 677307). AR 676679 states that "there was No leakage observed between the concrete floor and the riser valve (No Class 3 piping pressure boundary leakage observed). No degradation identified, no actions taken.
10/10/07	The licensee documented in UT report No. 2007-474 and AR 00682786, the 0H SX riser pipe wall thickness measured at 3 areas around the pipe perimeter. The minimum pipe wall thickness recorded at one location was 0.085 inches and 0.154 and 0.150 at the other two locations.
10/12/07	The licensee completed Operability Evaluation 07-009 and EC 367754 for the 0H SX riser pipe. The licensee concluded that the piping was operable based on new minimum acceptable wall thickness of 0.06 inch and the licensee predicted a remaining life of 2.1 years for this pipe section.

TIMELINE OF EVENTS - SX RISER PIPE DEGRADATION

10/17/07	The licensee documented in UT report No. 2007-478 and AR 00685955, the 0B riser pipe wall thickness measured at 10 areas around the pipe perimeter. The pipe wall thickness measured was below 0.1 inch at each of these locations and the lowest reading recorded was 0.047 inch. The licensee documented and accepted the 0B SX riser pipe wall thickness measurements in AR 00685955 "Minimum Wall on SX Riser Piping, 0SX97AB-24." Specifically, the licensee applied equation 9D of Appendix F from EC 367754 to determine a new minimum allowable wall thickness for SX Return Riser pipe of 0.03 inch.
10/17/07	During a Byron Station risk meeting, licensee staff suspends UT wall thickness measurement until they have a "go forward plan." Following the risk meeting two new AR's were generated to clean/ clear SX riser. Licensee develops an Adverse Condition Monitoring Plan.
10/19/07 03:01	0C SX riser missile barrier removed to allow access for inspection.
10/19/07 03:30	0C SX riser inspections resume.
10/19/07 12:00-17:30	Shift Manager requests Regulatory Assurance for assistance / advice on how to deal with TRM 3.4.f in the event of further degradation of SX piping. Regulatory Assurance starts investigating options on how to proceed if TRM 3.4.f needed to be implemented. Regulatory Assurance considers several options prior to the leak developing. 10CFR 50.54x option was considered and rejected. TRM 3.0.c was considered and rejected. Changing the TRM was considered and determined to be too time consuming.
10/19/07 17:30	0C SX riser develops a through wall leak during cleaning efforts to support UT of "C" Riser (reference AR 00640363 Assign #2) result in through-wall leak.
10/19/07 17:30	Based on leak at 0C SX riser the operations staff declare the ultimate heat sink inoperable and enter TRM TLCO 3.4.f and LCO 3.7.9. Condition G. LCO 3.7.9 required both units to be in Mode 3 within 6 hours. (e.g., 23:30).
10/19/07 17:30	Because of the 0C SX riser leak, the licensee considers that the ASME Code Class 3 SX riser pipe no longer has structural integrity, which requires the licensee to enter into TLCO 3.4.f Condition B. Condition B requires isolation of the 0C SX riser immediately or restoration of structural integrity immediately. The Shift Manager, with input from his upper management chain of command and input from Regulatory Assurance, determine that it was not prudent to isolate Unit 1 and Unit 2 A Train Safety Systems during the duel unit shutdown required by LCO 3.7.9, Ultimate Heat Sink Condition G. This decision was primarily based on the fact that Online Risk would increase to an 'Orange' level due to the unavailable/isolated equipment.
10/19/07	Unit 2 shutdown begins with power reduction at 5 megawatts per minute.

18:30	
10/19/07 18:32	Unit 1 shutdown begins with power reduction at 5 megawatts per minute.
10/19/07 22:43	Unit 1 turbine generator is tripped.
10/19/07 21:48	0D SX riser missile barrier is removed to allow access for inspection.
10/19/07 22:50	Unit 2 turbine generator is tripped.
10/19/07 23:09	Unit 2 reactor is tripped and Mode 3 is achieved.
10/19/07 23:12	Unit 1 reactor is tripped and Mode 3 is achieved.
10/20/07 04:30	0F SX riser missile barrier removed to allow access for inspection.
10/20/07 19:07	Unit 2 enters Mode 4.
10/20/07 21:22	Unit 1 enters Mode 4.
10/20/07 23:56	Unit 1 enters Mode 5.
10/21/07 00:00	Unit 2 enters Mode 5.
10/21/07 01:35	Clearance order issued to isolate the 0B cooling tower basin initiated (e.g., 0E, 0F, 0G, & 0H SX riser pipes). The first of three checklists was entered as completed at 11:44. The other checklists were created to address isolation valve leakage.
10/21/07 10:40	0E SX riser missile barrier removed to allow access for inspection.
10/21/07 11:58	0G & 0H SX riser missile barrier removed to allow access for inspection.

PICTURES OF DEGRADED SX COMPONENTS

Picture No. 1 - 0A SX Riser Pipe – October 19, 2007

Picture No. 2 - 0B SX Riser Pipe- November 30, 2006

PICTURES OF DEGRADED SX COMPONENTS

Picture No. 3 – 0C SX Riser Pipe- October 19, 2007

Picture No. 4 – 0D SX Riser Pipe- October 22, 2007

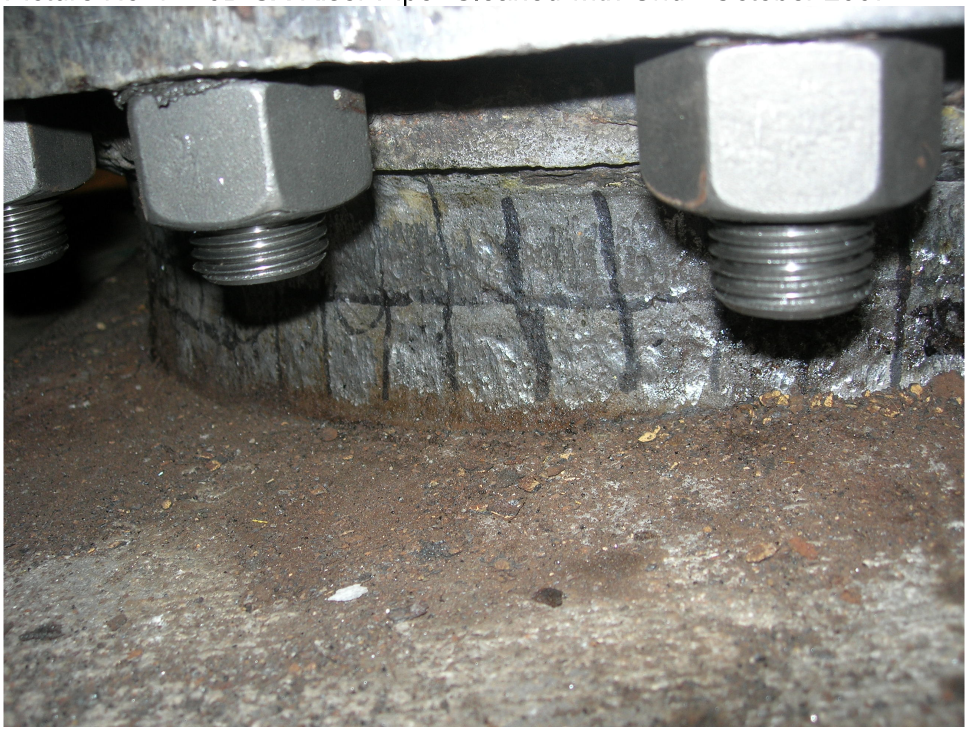
PICTURES OF DEGRADED SX COMPONENTS

Picture No. 5 – 0E SX Riser Pipe- June 14, 2007

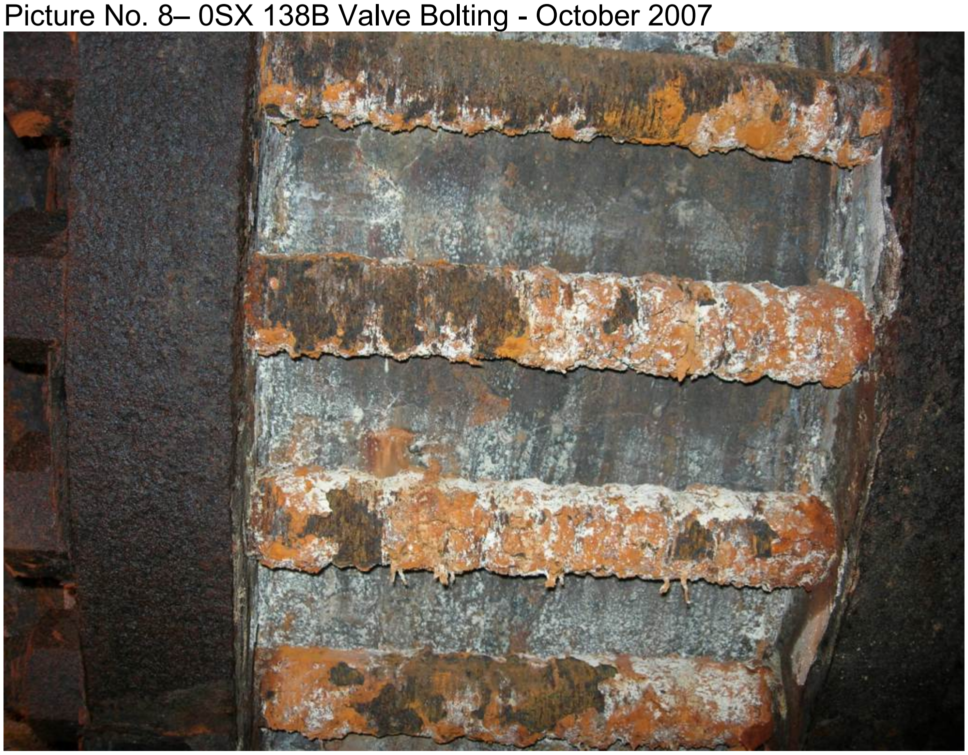
Picture No. 6 – 0F SX Riser Pipe Removed, Cleaned, with Grid- October 25, 2007

PICTURES OF DEGRADED SX COMPONENTS

Picture No. 7 – 0D SX Riser Pipe- Cleaned with Grid - October 2007



Picture No. 8– 0SX 138B Valve Bolting - October 2007



BYRON SPECIAL INSPECTION TEAM CHARTER

October 23, 2007

MEMORANDUM TO: Mel Holmberg, Senior Reactor Engineer
Division of Reactor Safety

FROM: Steven West, Director
Division of Reactor Safety

SUBJECT: SPECIAL INSPECTION CHARTER TO REVIEW DEGRADATION OF THE ESSENTIAL SERVICE WATER RISER PIPING TO THE COOLING TOWER BASIN AT THE BYRON NUCLEAR STATION

On May 17, 2007, based on visual inspection, the licensee generated a condition report regarding extensive corrosion degradation of the 0A essential service water riser into the cooling tower basin and noted similar corrosion on the other risers, but did not perform ultrasonic thickness measurements at that time. Based on this condition report, the licensee, on June 14, 2007, completed ultrasonic thickness measurements of the OE riser and generated a condition report for that riser. On October 10, 2007, the licensee completed ultrasonic thickness measurements on the OH riser and generated a condition report for that riser. On October 17, 2007, the licensee completed ultrasonic thickness measurements on the OB riser and generated a condition report for that riser. In the three later cases, the licensee calculated new minimum allowable wall thickness values and considered the degraded piping as operable.

The issue was discussed during an internal licensee meeting on October 17, 2007, including the timeline for completing ultrasonic thickness measurements of the remaining risers. There appeared to be differing interpretations of the outcome/decisions of that meeting which the NRC senior resident inspector discussed with the licensee on October 18, 2007, and a follow-up call between Region III management and staff and the licensee occurred later that day. During that call, the licensee outlined their plan for continued examinations and discussed their rationale for continued operability. The licensee indicated they would evaluate several questions posed from NRC staff regarding their operability determination. A follow-up call between Region III and NRR management and staff and the licensee occurred on October 19, 2007, during which operability was again discussed (licensee was still evaluating the NRC questions), and the possible need for ASME Code relief for repairs was explored. Later that evening, a leak developed on the OC riser pipe while removing corrosion to facilitate ultrasonic measurements. As a result, the licensee declared the ultimate heat sink for both units inoperable, and performed a dual unit shutdown as required by Technical Specifications. Contrary to the licensee's Technical Requirements Manual, the licensee did not isolate the line after the leak developed.

Management Directive 8.3 and IMC 309 Review

The circumstances surrounding the essential service water riser pipe degradation was evaluated against the criteria in Management Directive 8.3 and Inspection Manual Chapter 0309. Deterministic Criteria g and h were met. A conditional core damage probability (CCDP) estimate for a reactor transient was performed to represent the dual unit plant shutdown. The essential service water system was determined to be available because the leak on the OC riser was well within the capacity of the essential service water makeup system and as a result there was no loss of essential service water function. The CCDP estimate using the NRC's simplified plant analysis risk model (SPAR), revision 3.31 was 2.6E-6. This estimate is within the range of a special inspection.

The risk calculation does not consider the potential impact of the degradation of the essential service water system due to corrosion and pipe wall thinning. A quantitative risk estimate cannot currently be estimated for this condition. Excessive pipe wall thinning could contribute to an increase in the loss of essential service water initiating event frequency. Since the loss of essential service water event is generally a high consequence event and the pipe degradation appears to be common across all essential service water risers, qualitative risk insights also support a special inspection. The decision to charter a Special Inspection was coordinated with the Office of Nuclear Reactor Regulation and Nuclear Security and Incident Response

Special Inspection Activities

The Special Inspection will commence on October 23, 2007, and be led by Mel Holmberg, senior reactor engineer (ISI specialist). In addition to Mr. Holmberg, the team will consist of Tom Bilik (ISI specialist), Vijay Meghani (structural specialist), and Carl Moore (operations specialist). The inspection will likely be supplemented by one additional inspector. Office of Nuclear Reactor Regulation technical staff will be available for consultation as will Region III Senior Reactor Analysts.

The inspection will evaluate the fact, circumstances, and licensee actions surrounding the degradation of the riser piping. A charter was developed and is enclosed. An entrance meeting will be conducted on Tuesday, October 23, 2007.

BYRON SPECIAL INSPECTION TEAM CHARTER

This Special Inspection is chartered to assess the circumstances surrounding the degradation of the essential service water risers into the cooling tower basin affecting both Byron Units 1 and 2. The Special Inspection will be conducted in accordance with Inspection Procedure 93812, “Special Inspection,” and will include, but not be limited to, the following items:

1. Establish a sequence of events regarding licensee identification and actions to address degradation of the essential service water riser piping.

2. Monitor the licensee’s efforts to determine the root cause of the essential service water riser piping degradation and evaluate acceptability of these efforts including the timeline for feeding back results into current evaluation and repair efforts.

3. Evaluate the adequacy and effectiveness of licensee processes (i.e. ISI, condition reporting, etc.) and implementation thereof to identify and address the essential service water riser piping degradation in a timely manner. Include evaluation of any licensee decisions and communication thereof coming out of the licensee’s internal October 17, 2007, meeting.

4. Evaluate the adequacy of the licensee’s past operability decisions for the essential service water riser piping degradation.

5. Evaluate the adequacy of the repair plan and monitor implementation. Confirm compliance with ASME Code requirements and the methodology to show this compliance and evaluate the licensee’s conclusions regarding the need or lack thereof for ASME Code relief.

6. Evaluate the adequacy of the licensee’s plans regarding the condition and operability of essential service water riser piping for restarting the units and any subsequent repairs. Include the adequacy of the licensee’s decision to choose risers OF and OG for destructive evaluation in order to provide insights for subsequent decisions regarding riser OD. Also include review of the revision to ECC 0000367082 regarding change in required number of cooling tower fans.

7. Evaluate suitability and risk significance of the licensee’s decisions and actions regarding not following direction in the Byron Technical Requirement’s Manual to isolate piping after identifying a leak in the essential service water riser.

8. Evaluate the risk significance of the as-found condition (before and after the leak) regarding the essential service water riser piping degradation.

9. Evaluate the adequacy and monitor implementation of licensee extent of condition plans. Confirm these plans include gathering information to support evaluating risk significance.

PRELIMINARY - NRC IMC 609 – Appendix M TABLE 4.1
Qualitative Decision-Making Attributes

Decision Attribute	Applicable to Decision?	Basis for Input to Decision - Provide qualitative and/or quantitative information for management review and decision making.
1. Finding can be bounded using qualitative and/or quantitative information?	Yes.	The degraded SX riser pipe condition was caused by external pitting and general corrosion due to a lack of a protective coating and resulted in wall thinning that increased the likelihood of pipe rupture. The increase in frequency of pipe rupture is unknown, but judged to be non-negligible. Pipe rupture can lead to a loss of essential service water event (bounding assumption), which is a generally a low frequency, high consequence event. EPRI 1013141, "Pipe Rupture Frequencies for Internal Flooding PRAs" provides a conditional probability of rupture given failure for service water piping of 7.1E-4. This value is for ruptures resulting in a flow rate greater than 2000 gpm and is largely based on judgment given that no failures of service water piping of this magnitude were identified for the study. Operating Experience – IN 2007006 indicates that catastrophic failures of service water piping due to external corrosion have occurred. Quantitative risk insights indicate that the significance of the finding is no greater than Yellow. The licensee's evaluation concluded that there is increased risk due to the potential for pipe rupture(s) during beyond design basis seismic events and that the risk is bounded as a White finding.
2. Defense-in-Depth affected?	Yes	Degradation in the SX piping increases the loss of SX initiating event frequency. This increases the frequency of an RCP seal LOCA which impacts the RCS barrier. Also, the initial SX design adds significant defense-in-depth by incorporating redundant basin risers. Defense-in-depth is significantly impacted by the common cause degradation of all eight of these risers.
3. Performance Deficiency effect on the Safety Margin maintained?	Yes	In this case, "Safety Margin" was evaluated by review of margins available to prevent SX pipe material failures. The original pipe design Code maintains margins to ensue the pipe material remains well within elastic material property ranges. The licensee analysis performed (EC 368389) demonstrated that elastic margins would not be maintained in the degraded pipe areas, and instead would be subject to plastic deformation within the pipe material limits. In particular, for SX riser pipes 0A, 0B, 0C, 0D, 0E, with multiple areas of pipe wall thickness below 0.1 inch and/or the presence of through-wall holes, local areas of the pipe were subject to plastic deformation. Because elastic material behavior under normal and accident loads was no longer

		assured, the team concluded, based on engineering judgment, that the SX riser pipes had an increased probability of rupture.
4. The extent the performance deficiency affects other equipment.	Yes.	Each of eight SX riser pipes experienced external corrosion and pipe wall loss which affected the independent SX trains in both Units and potentially represented a common cause failure mode for the SX systems.
5. Degree of degradation of failed or unavailable component(s)	Yes.	Original 24 inch diameter SX riser pipe wall thickness = 0.375 inch. After corrosion: 0A Riser – Four pipe wall areas below 0.1 inch which extended for several inches along the pipe perimeter. Average pipe wall thickness of 0.190 inch. 0B Riser – One corrosion product filled elliptical hole was identified with a maximum length dimension of 0.74 inch. One pipe wall area reduced to approximately 0.1 inch thick. Average pipe wall thickness of 0.203 inch. 0C Riser – Four holes were identified (three at approximately 0.5 inch diameter & one at approximately 0.18 inch diameter). Three holes were filled with corrosion products. Six pipe wall areas reduced to below 0.1 inch, three of which extended for several inches along the pipe perimeter. Average pipe wall thickness of 0.168 inch. 0D Riser – Eight pipe wall areas reduced below 0.1 inch, which extended for several inches along the pipe perimeter. One area was characterized as a three inch long gouge in the pipe wall. Average pipe wall thickness of 0.148 inch. 0E Riser – Three pipe wall areas reduced below 0.1 inch, one of which extended for several inches along the pipe perimeter. Average pipe wall thickness of 0.168 inch. 0F Riser – No localized areas below 0.1 inch. Average pipe wall thickness of 0.198 inches. 0G Riser – No localized areas below 0.1 inch. Average pipe wall thickness of 0.183 inches. 0H Riser – One local thin area (gouge) 0.080 inch believed to have been caused by a mechanical process (e.g. cutting or grinding). Average pipe wall thickness of 0.252 inch.
6. Period of time affect on the performance deficiency.	Yes.	Corrective action Violation performance deficiency > 1 yr in duration with 0C riser having the maximum time (May of 2006 through October 2007). Design control Violation errors in support of operability evaluations performance deficiency ~ 0.25 yr with the 0E SX riser pipe having the maximum time July thru October 2007. Degradation of SX riser pipes occurred for many years. Exposure time to assume for risk analysis is 1 yr in duration.

7. The likelihood that the licensee's recovery actions would successfully mitigate the performance deficiency.	Yes.	Through-wall leakage of these risers may not have been quickly detected because the SX risers are in enclosed vaults. Additionally no routine operating surveillance procedures existed to monitor the vault drains for evidence of leakage flow. First indications of a pipe rupture may be the increased makeup flow required to maintain SXCT basin levels. Due to leakage in SX isolation valves needed to isolate independent trains, capability to isolate a SX riser pipe rupture is in doubt. Specific procedures for performing this isolation do not exist. Procedures exist for aligning the fire protection system to the charging pump lube oil coolers to maintain adequate cooling of the pumps for continued operation. This action is necessary in a loss of SX event to prevent an RCP seal LOCA. Adequate time would be available to complete the actions. These actions are credited in the licensee's PRA and in the NRC's SPAR model. Procedures exist for aligning the fire protection system or non-essential service water system to the SX system as a result of a loss of essential service water event. These actions are not yet credited in the licensee's PRA or in the NRC's SPAR model. Limited training has been conducted. NRC Inspector reviews indicate actions may be feasible.
8. Additional qualitative circumstances associated with the finding that regional management should consider in the evaluation process	Yes	The following qualitative factors were considered in evaluating the increase in probability of SX pipe rupture. • Thermal expansion induced bending moments and compressive loads create the dominant pipe load at the degraded SX riser pipe locations. Therefore, many operational transients (e.g. Single or Dual Unit shutdown) and accident scenarios (e.g. loss of offsite power) exist which could induce loads on the SX risers that may challenge structural integrity. • Five SX riser pipes were degraded such that elastic material behavior is not assured during design basis accidents or operational transients. The location of wall thinning was fortuitous in that the areas of maximum thinning did not form at pipe azimuth locations which experienced the greatest operational stresses. Had this occurred, the SX riser pipes may have experienced a more substantial failure or rupture. • Licensee calculations demonstrated for internal events and seismic loads within design basis, that a margin remains to plastic strain, induced material failure limits (up to 7 percent plastic strain predicted). • Two SX riser pipes (0B and 0C) contained through-wall holes and the 0C SX riser contained four through-wall holes.

		• Licensee calculation (EC 368389) demonstrates that adequate SX makeup (with margins) existed to account for leakage from the SX riser pipe through-wall holes. • For a postulated SX riser pipe rupture, a portion of the water will likely be held up in the service water vault enclosure and return to the ultimate heat sink through the failure of the vault's back wall (sheet metal). The amount lost from the vaults and not returned to the SXCT basin is subject to a large amount of uncertainty. • A relatively large break is needed to overcome makeup sources and due to the large SXCT basin inventory (e.g. greater than 600,000 gallons), several hours would be available for corrective measures in the event of a large break.