From: Elaine Raphael
To: Joelle Starefos
Date: 8/20/02 9:04AM
Subject: Draft Document

Good morning Joelle:

FOR YOUR EYES ONLY!

Attached is the DB Lessons learned draft document. The document is broken into sections Please inform Bob of any changes.

thanks,
Elaine

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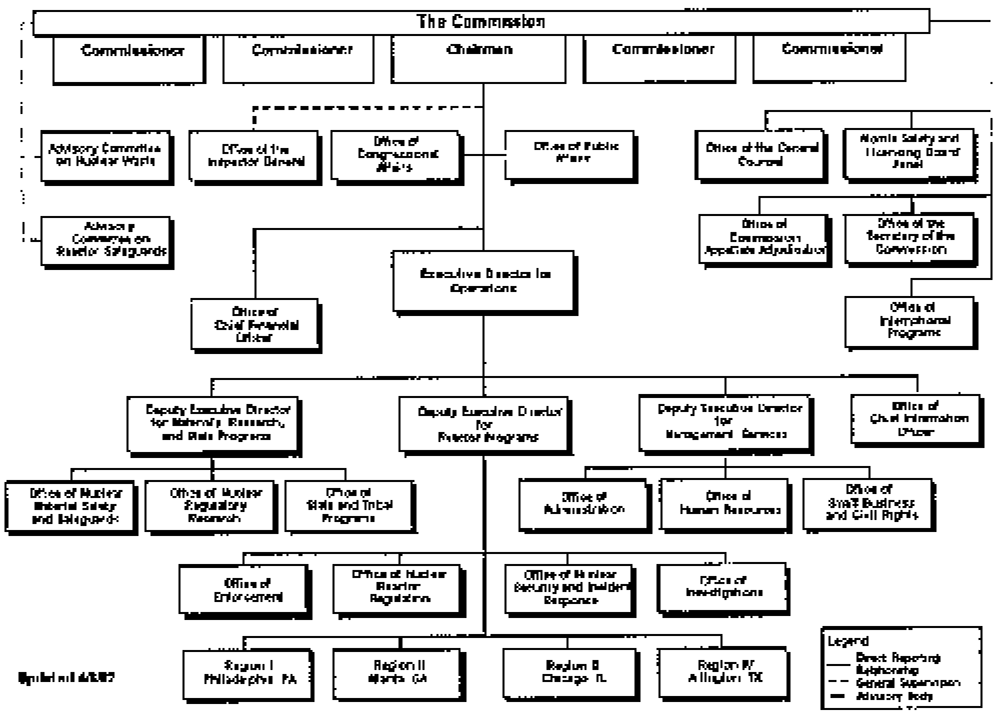
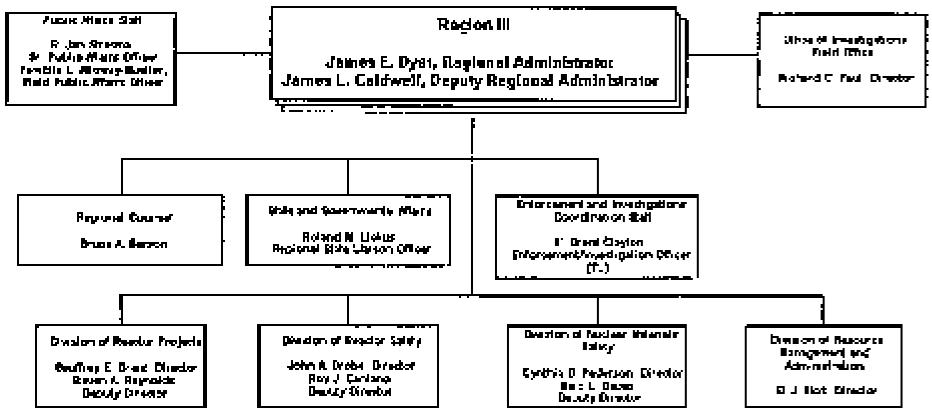


Figure 1-1 NRC Organization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Bruce A. Berson
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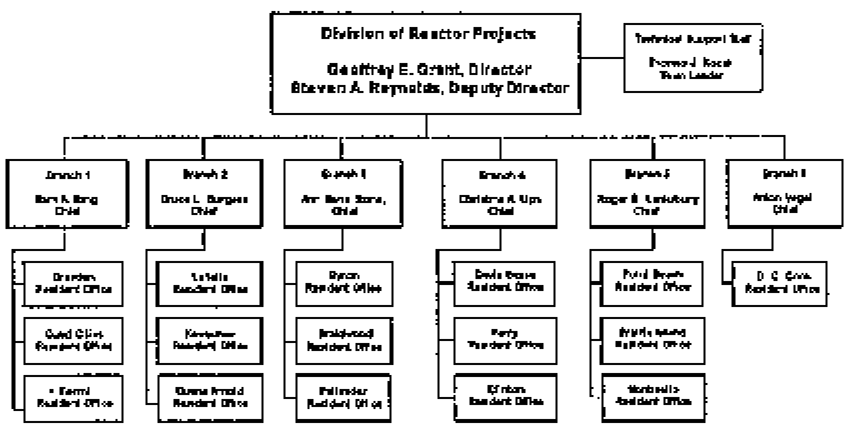
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Resident Office
Braidwood
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Palisades
Resident Office
Davis Besse
Resident Office
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Prairie Island
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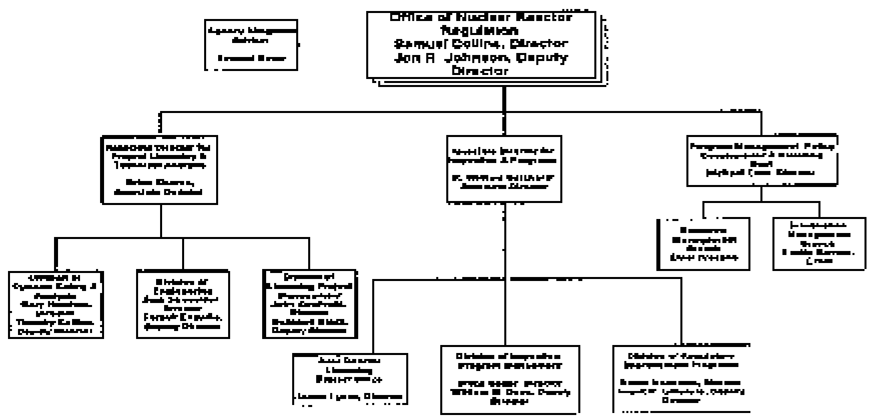
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Jon R. Johnson, Deputy Director

2.0 Condition Summary and Background

2.1 Condition Summary

On February xx, 2002, staff of the First Energy Nuclear Operating Company (FENOC), the licensee for the Davis-Besse Nuclear Plant in Oak Harbor, Ohio, discovered a cavity in the reactor vessel head, adjacent to the number 3 reactor vessel head penetration (VHP) as shown in Figure 2.1). This discovery came as the plant was shutdown for a refueling outage during which the licensee was conducting inspections for VHP cracking due to Primary Water Stress Corrosion Cracking (PWSCC) in reaction to NRC Bulletin 2001-01 (August 2001) [ref]. During these inspections, cracks were discovered in several VHPs, including VHP number 3. The licensee had contracted with the Framatome Nuclear Company to perform repairs of cracked VHPs, where necessary, by machining away the affected portion of the VHP and re-establishing the pressure boundary by welding the VHP further up into the reactor vessel head as shown in Figure 2.2. Such repair practices had been successfully implemented previously at the Oconee Nuclear Station (ONS) and had been approved by the NRC.

During the machining process to repair the number 3 VHP, the penetration was observed to wobble as the original pressure boundary weld was removed. Under normal circumstances, such movement of the VHP would not have been possible since the VHP is laterally restrained by over six inches of reactor vessel head material. The wobble led FENOC to examine the region adjacent to VHP number 3 and a cavity of approximately xx square inches was discovered (Figure 2.3). Upon further examination, the cavity was found to extend completely through the 6-1/4 inch thickness of the carbon steel reactor vessel head down to a thin internal liner of stainless steel cladding. Hence, immediately prior to the plant shutdown for refueling, the stainless steel cladding was acting as the primary system pressure boundary over the region of the cavity. In this case, the cladding contained the primary system pressure (2550 psi ?) over the cavity region during operation. However, the cladding is not designed to perform this function. Degradation of a nuclear plant primary system pressure boundary to this extent had not been observed previously either in the U.S., or internationally.

The exact mechanism(s) for the cavity degradation have not been established [ref - Root Cause Rpt] However, boric acid corrosion of the carbon steel is thought to be the primary degradation mechanism. The primary corrosive attack was likely caused by leakage from a through-wall crack in VHP number 3, but may have been assisted by VHP flange leakage onto the head from above.

2.2 Background

The Davis-Besse Nuclear Plant is a 2-loop pressurized water reactor (PWR). This means that there is a primary reactor coolant system (RCS) loop with two steam generators which transfer heat from the RCS to the secondary water. This heat causes the secondary water to boil, and the resulting steam is used to turn a turbine, which turns an electrical generator to produce electricity.

The Davis-Besse RCS fabricator was the former Babcock & Wilcox (B&W) Company. The B&W Company was subsequently acquired by the Framatome Nuclear Company.

PWRs utilize water as a primary coolant and as a "moderator" to control the nuclear reaction in the reactor vessel. In addition, such light water reactors (LWRs) employ "control" rods to enable further control of the nuclear reaction. In a PWR, these control rods enter the reactor vessel from atop the reactor vessel head (Figure 2.4) The reactor vessel (RV) head is fabricated from carbon steel and is attached to the reactor vessel through a bolted and flanged connection (Figure 2.4). The interior of the RV head is lined with stainless steel cladding as a barrier to general corrosion. The cladding is deposited through a welding process. For the typical B&W design, there are approximately 69 vessel head penetrations (VHPs) penetrations of the RV head for control rods

The VHPs of commercial U.S. pressurized water reactors (PWRs) are fabricated from Inconel 600 (also known as Alloy 600) and are approximately 4 inches in diameter and approximately ½ inch in wall thickness. Inconel 600 is an alloy containing primarily nickel, but also iron and chromium. The alloy and associated weld materials (alloys 82 and 182) are highly resistant to general corrosion, but can be susceptible to PWSCC. The VHPs are shrunk-fit and welded into pre-machined holes in the RV head. The VHPs are part of the reactor coolant pressure boundary, which is one of three principle barriers to the release of radioactive fission products. The VHP nozzles are joined to the reactor vessel head by J-groove welds that only partially penetrate through the head thickness (see Figure 2.5). PWSCC of a VHP nozzle or the weld connecting the nozzle to the vessel head can lead to leakage from the pressure boundary. If undetected and uncorrected, this type of degradation could potentially propagate to failure of the nozzle and result in a small-break loss-of-coolant accident (LOCA) for the plant. While this is not a desirable consequence, all commercial nuclear power plants are designed to accommodate certain postulated failures, including a VHP nozzle failure. All plants have emergency core cooling systems that will quickly inject coolant into the reactor and maintain it in a safe condition.

History of VHP Cracking

VHP cracking was first observed at the French PWR, Bugey 3, in 1989. This cracking involved axial (and circumferential?) through-wall cracking of an alloy 600 VHP due to PWSCC which led to leakage observed in a hydrotest. Since that time, it was known that alloy 600 VHPs were susceptible to stress corrosion cracking that could lead to through-wall leakage.

In reaction to the French experience, in 1991 the NRC implemented an action plan to address PWSCC of U.S. VHP s fabricated from alloy 600. This action plan included an NRC staff review of safety assessments conducted by the PWR owners groups (i.e., Westinghouse Owners Group, Combustion Engineering Owners Group and Babcock & Wilcox Owners Group) [refs]. These reports addressed VHP cracking and the potential for consequent boric acid degradation of RV heads from leakage through the VHP cracks. The U.S. industry reports concluded that axial cracking, even if through-wall, was not highly safety significant, circumferential cracking of VHPs was improbable and boric acid attack of the RV head, if it were to occur, would be discovered through required boric acid inspections well before safety margins would be compromised. In a safety evaluation dated November 19, 1993 [ref], NRC largely agreed with this assessment, but decided to reserve judgement regarding circumferential cracking to a case-by-case basis, and encouraged the industry to develop enhanced VHP leakage monitoring techniques.

The U.S. industry conducted pilot inspections of VHPs at three U.S. Nuclear plants (Oconee, D.C. Cook and Point Beach?) in the mid 1990s. These inspections revealed only minor axial partial wall cracking at the Cook plant. However, in 1997 continued NRC concern with this issue led to issuance of GL 97-01 [ref] which requested licensees to inform NRC of their plans relative to VHP inspections. Inspections in reaction to GL-97-01 led to the discovery of extensive circumferential cracking of a VHP at Oconee Nuclear Station (ONS) Unit 3 in the Spring of 2001. Prior to the discovery at Oconee, circumferential cracking in VHPs, particularly to the extent observed at Oconee had been considered to be improbable. Circumferential cracking in VHPs is more safety significant than axial cracking since it creates the potential for ejection of the penetration if the cracking is severe enough. In reaction to the Oconee cracking, NRC issued Bulletin 2001-01 [ref] which requested licensees to address the potential for similar cracking at their plants and discuss their plans for VHP inspections. A key aspect of addressing the potential for cracking was the effectiveness of visual examinations for leakage on the RV heads. The EPRI/MRP took the lead for the industry in "binning" plants by susceptibility relative to Oconee. The binning was accomplished through consideration of operating time and operating temperature. The B&W units (like Oconee and Davis-Besse) operate with the highest RV head temperatures and were all considered to be highly susceptible to potential for circumferential cracking. By November, 2001, all of the B&W units except Davis-Besse had either effectively inspected their VHPs, or provided justification to NRC as to why previous inspections and plant fabrication and operational characteristics indicated that extensive circumferential cracking at their plants was not likely.

Finish with cracking predicted for DB, deferral, discovery of cavity ....

History of Boric Acid Degradations

- Precursor events (incl. Beznau)
- GL 88-05
- EPRI Handbook
- 1992 DB SG shell degradation
- 1998 DBRC 2 degradation

Regulatory Requirements

- GDC's RCPB leakage
- Tech Specs
- Commitments to GCs

2b

Figures

References

The NRC implemented an action plan in 1991 to address primary water stress corrosion cracking (PWSCC) of U.S. VHP nozzles fabricated from Alloy 600. This action plan included a staff review of safety assessments conducted by the PWR owners groups (i.e., Westinghouse Owners Group, Combustion Engineering Owners Group, and Babcock & Wilcox Owners Group). After reviewing these assessments and examining pertinent overseas inspection findings, the NRC staff concluded, in a safety evaluation (SE) dated November 19, 1993, that PWR VHP nozzle and weld cracking was not an immediate safety concern. The staff based this conclusion on the following determinations: (1) if PWSCC were to occur in a VHP nozzle, any cracks would be predominately axial in orientation, (2) the cracks would result in leakage from the nozzle to the reactor vessel head prior to any failure, and (3) the leakage would be detected during visual examinations performed as part of surveillance walkdown inspections before significant damage to the reactor vessel closure head would occur. However, in the SE, the NRC staff also stated that it had concerns about the potential for circumferential cracking to occur in these nozzles. Circumferential cracks are of greater concern because they could lead to a separation of the nozzle from the reactor vessel, which could not occur if the cracks were only oriented axially along the length of the nozzles. The SE stated that there was a need for the industry to develop enhanced leakage monitoring methods for detecting boric acid leakage from these nozzles and that new information and events could require the staff to reassess its conclusions as to the safety significance of the issue.

By letter dated March 5, 1996, the Nuclear Energy Institute (NEI)* submitted a white paper entitled "Alloy 600 RPV Head Penetration Primary Stress Corrosion Cracking," the purpose of which was to describe how the PWR licensees were managing the issue. On April 1, 1997, the staff issued Generic Letter (GL) 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," to all of its PWR-licensees requesting that they describe the programs they had or planned to put in place to monitor and manage cracking found in VHP nozzles and inform the Commission of their intentions, if any, to perform augmented volumetric or surface examinations of the VHP nozzles for their nuclear plants. Issuance of this generic letter was noticed in pages 17887-17888 of Volume 62, *Federal Register*, No. 70, dated Friday, April 11, 1997. The NRC encouraged the industry to address this issue both on a plant-specific basis and on a generic basis. In July 1997 the Westinghouse Owners Group, Combustion Engineering Owners Group and Babcock & Wilcox Owners Group submitted their generic responses to GL 97-01 on behalf of their member utilities. The generic responses ranked the potential for the VHP nozzles of their member plants to develop stress corrosion cracking. Later, in 1998, NEI revised the rankings and developed an integrated program for inspecting the VHP nozzles of U.S. PWRs. NEI forwarded this program to the NRC for review by letter dated December 11, 1998. In regard to implementation of this program, NEI stated that licensees owning U.S. PWRs should continue to perform required visual examinations of their vessel heads for leakage, and highly recommended that plants having the most susceptible VHP nozzles implement voluntary eddy current examinations of their nozzles. NEI also stated that this program would be modified, as necessary, based on the results of all examinations performed on U.S. VHP nozzles and any other pertinent information that could provide a basis for modifying the program. The NRC staff found this approach acceptable. The NRC documented this in a letter to NEI dated March 21, 1999.

On February 18, 2001, with Unit 3 of the Oconee Nuclear Station (Oconee Unit 3) shut down, Duke Energy Corporation (Duke) performed a visual examination of the outer surface of the unit's reactor pressure vessel (RPV) head for indications of leakage. This visual examination revealed the presence of leakage in the vicinity of nine of the 69 control rod drive mechanism nozzles (a type of VHP nozzle). Upon commencing with required ASME Code Section XI repair activities of the affected CRDM nozzles, Duke identified that the flaw indications (cracks) in two of the nozzles were larger than was originally thought and had circumferential orientations to them. The extent of the length of the circumferential portions of the cracks followed the weld profile contour and were nearly 165@ in length. Duke later reported that a third CRDM nozzle at Oconee Unit 3 also had a circumferential crack approximately 45 @ in length.

Similar stress corrosion cracking and reactor coolant pressure boundary leakage have been reported at the other two reactor units of the Oconee Nuclear Station (i.e., at Unit 1 in November 2000, and Unit 2 in April 2001) and at the reactor unit of Arkansas Nuclear One, Unit 1 (i.e., ANO Unit 1 in February 2001). Most of the cracking has been in the axial direction. The circumferential cracking is significant in that it represents the first reported occurrence of such cracking in the VHP nozzles of U.S. PWRs and raises concerns about a potentially risk-significant condition that could affect some domestic PWRs.

The circumferential cracking reported at the Oconee site has prompted the NRC and industry to re-evaluate the validity of some of the previous technical assumptions. This re-evaluation is consistent with the conclusions of NRC's SE of November 19, 1993, which stated the staff may need to reassess its conclusions as to the safety significance of the issue based on new relevant information or cracking events. The circumferential cracking reported at Oconee also reinforces the importance of examining the upper PWR RPV head area using techniques that are capable of detecting leakage from the VHP nozzles and their associated J-groove welds and heat-affected-zones. Presently, Section XI of the ASME Boiler and Pressure Vessel Code does not require licensees to remove RPV head insulation prior to inspecting their reactor vessel heads and VHP nozzles.

After the initial finding of circumferential cracking at Oconee Unit 3, the NRC held a public meeting with NEI and the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) on April 12, 2001, to discuss circumferential cracking issues for U.S. VHP nozzles. During the meeting, the industry representatives indicated that they were developing a generic safety assessment, recommendations for revisions of near-term inspections, and long-term inspection and flaw evaluation guidelines to address this issue. On May 18, 2001, the MRP submitted the MRP-44, Part 2, report to provide an interim safety assessment for PWSCC of Alloy 600 VHP nozzles and their associated J-groove welds. To address the experience at Oconee Nuclear Station, the MRP recommended that plants considered to be highly susceptible to this form of cracking and having fall 2001 outages should perform a visual inspection of the RPV top head capable of detecting small amounts of reactor coolant leakage similar to that observed at the Oconee units and ANO Unit 1.

On June 7, 2001, the NRC held a public meeting at which the MRP provided initial responses to questions on the MRP-44, Part 2, report that the NRC staff had identified and transmitted to the MRP on May 25, 2001. The NRC staff provided additional questions on various aspects of the MRP-44, Part 2, report in a letter to the MRP dated June 22, 2001. In this letter, the staff informed the MRP that the staff had two areas of concern with the industry's methodology provided in Topical Report MRP-44, Part 2. With respect to the first area of concern, the staff informed the MRP that the conclusion that nozzle leaks would be detectable on all vessel heads would require validation. This concern was addressed in the Bulletin and licensee responses to the Bulletin. With respect to the second area of concern, the staff informed the MRP that the conclusion that the appropriate crack growth rate for OD-initiated cracking of VHP nozzles was adequately represented by crack growth data for Alloy 600 steam generator tubes would also require validation. This concern continues to be investigated.

Based on the review of industry report MRP-44, Part 2, the NRC staff concluded that additional plant-specific information was necessary to assure that licensees were taking actions to effectively maintain the integrity of their VHP nozzles. Therefore, on August 3, 2001, the Commission issued NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," to address the generic safety implications of the pressure boundary leakage found at the Oconee Nuclear Station and ANO Unit 1 power plants. In the Bulletin, the staff discussed the technical aspects of plant designs that could impede the ability of visual examination methods to detect leakage from the VHP nozzles of commercial U.S. PWRs. The staff emphasized that the ability to detect reactor coolant leakage from the VHP nozzles could be limited if the visual examination methods for detecting the leakage were incapable of distinguishing between boric acid residue deposited as a result of VHP nozzle leaks and those previously deposited as a result from leakage from other sources.

In the Bulletin, the staff categorized the VHP nozzles for U.S. PWRs into four populations based on a plant's susceptibility ranking as given in Appendix B to the MRP-44, Part 2, report. For the population of plants considered as having low susceptibility based upon a susceptibility ranking of more than 30 EFPY (effective full power years) of operation from the Oconee Unit 3 condition, the staff stated that the likelihood of PWSCC degradation at these facilities was low, and that enhanced examinations beyond those required by Section XI of the ASME Code were not necessary at the present time.

For the population of plants considered as having a moderate susceptibility to PWSCC based upon a susceptibility ranking of more than 5 EFPY but less than 30 EFPY of operation from Oconee Unit 3, the staff stated that an effective visual examination capable of detecting and discriminating small amounts of leakage or boric acid deposits from 100 percent of the VHP nozzles would be sufficient to provide reasonable confidence that PWSCC degradation would be identified prior to posing an undue risk. The staff emphasized that this effective visual examination should not be compromised by the presence of insulation, existing deposits on the RPV head, or other factors that could interfere with the detection of leakage.

For the population of plants considered as having a high susceptibility to PWSCC based upon a susceptibility ranking of less than 5 EFPY of operation from the Oconee Unit 3 condition, the staff stated that the possibility for leaks to occur from a VHP nozzle at one of these facilities would dictate the need to use a qualified visual examination that would be capable of reliably detecting and accurately characterizing leakage from through-wall cracks in the VHP nozzles. With respect to an examination of this sort, the staff concluded that the qualified visual examination methods should be characterized by the following aspects: (1) that, as a result of a plant-specific demonstration, any VHP nozzle exhibiting through-wall cracking would be capable of providing a sufficient leakage path to the RPV head surface (based on the as-built configuration of the VHPs), and (2) that the effectiveness of the qualified visual examination should not be compromised by the presence of insulation, existing deposits on the RPV head, or other factors that could interfere with the detection of leakage. Absent the use of a qualified visual examination, the staff stated that a qualified volumetric or surface examination of 100 percent of the VHP nozzles (with a demonstrated capability to reliably detect cracking on the OD of a VHP nozzle) would be appropriate to provide evidence of the structural integrity of the VHP nozzles.

For the population of plants which had already identified the existence of PWSCC in the CRDM nozzles (for example, through the detection of boric acid deposits), the staff concluded there was a sufficient likelihood that the cracking of VHP nozzles will continue to occur as the facilities continue to operate, and that a qualified volumetric examination of 100 percent of the VHP nozzles (with a demonstrated capability to reliably detect cracking on the OD of the VHP nozzle) would be an appropriate method of providing evidence of the structural condition of their VHP nozzles

In the Bulletin, the staff requested that licensees inform the NRC of their plans, if any, to perform augmented examinations of their VHP nozzles and provide their technical basis for the timing and method of inspection. The staff required addressees to submit their responses to NRC Bulletin 2001-01 within 30 days of issuance of the Bulletin Licensee are currently implementing their inspections plans and additional cracking has been detected in some of the VHP nozzles of Crystal River Unit 3, Three Mile Unit 1, North Anna Unit 1 and Unit 2, and Surry Unit 1. None of the cracks in these VHP nozzles were reported as through-wall circumferential cracks, although one of the cracks detected at Crystal River Unit 3 has been reported as a partial through-wall circumferential crack 90° in length. When cracking is found in these nozzles, the components are being repaired before the units are returned to service.

Figure 1. Schematic of Typical CRDM Nozzle Penetration

3.1 The NRC and Industry Failed to Assess Operating Experience Relevant to Alloy 600 Nozzle Cracking and Boric Acid Corrosion of Carbon Steel Components

Despite the large accumulation of data on primary system leakage and boric acid corrosion of carbon steel components, timely corrective action to address boric acid buildup on the Davis-Besse reactor pressure vessel head was not taken. Both the NRC and Industry has obtained a significant amount of operating experience regarding boric acid leakage and corrosion of carbon steel components. For example, since 1980, 17 NRC generic communications have been issued providing examples of events involving either primary system leakage or corrosion of primary system components Numerous events contained in licensee event reports include leakage from pressurizer instrumentation, pressurizer heater sleeves, reactor coolant system instrumentation, control rod drive mechanism penetrations, excessive corrosion of fasteners on valves and the reactor head, reactor coolant system nozzles, pump casings, primary system piping, and miscellaneous component parts corroded by boric acid deposits. In addition to numerous primary system leaks, there have been pressurizer vessel base metal wastage events, and reactor pressure vessel head wastage. The significance of many of these events were either lost or forgotten when making an assessment of Davis-Besse.

3.1.1 Operating Experience at Domestic Nuclear Power Plants

The majority of primary system leakage events and boric acid corrosion events listed in this report come from domestic operating experience. Although there are several events that have occurred at foreign plants, detailed information at foreign events is generally not available, and most of the data is restricted and cannot be published. As seen in this report, age and material condition of power plants plays a significant role. Appendix E of this report contains an analysis of domestic operating experience related to primary system leakage and boric acid corrosion from 1986 through the first quarter of 2002. In determining the correlation between age an event types, many of the figures have been plotted against the number of years of operation prior to the event date. In addition to data obtained in LERs, NUREGs have been also been issued dealing with boric acid corrosion and cracking of nozzle penetrations

3.1.2 Operating experience reviews by NRR

Longer term operating experience reviews were accomplished by the Office for Analysis and Evaluation of Operational Data (AEOD) until 1999. AEOD was established as a lesson learned from the accident at Three Mile Island in 1979. As a cost-cutting and consolidation effort, AEOD was eliminated and many of the duties of AEOD were transferred to NRR in 1999. However, since these functions were given to NRR, most operating experience reviews done by NRR involve current events, and do not currently involve looking at operating failure trends or history. Per NRR management, NRR is still looking at the scope of what should be done by the NRC in the area of operating experience history.

3.1.3 Generic Communication Program

3.1.4 Generic Issue Program

3.1.5 (J) The Licensee Failed to Understand the Implications of Boric Acid Corrosion (**Action:**

Ron)
The significance of primary system leakage and the potential for boric acid corrosion was thoroughly understood. The response to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," provided by DB received only a cursory review. The original letter issued on September 4, 2001 was in the concurrence phase from August 20, 2001 through September 4, 2001. The "Supplemental Information in Response to NRC Bulletin 2001-01" was in the concurrence phase from October 17, 1002 through October 17, 2001. The "Response to RAIs Concerning NRC Bulletin 2001-01" was in the concurrence phase from October 30, 2001 through October 30, 2001. The "Transmittal of Davis-Besse Nuclear Power Station Risk Assessment of Control Rod Drive Mechanism Nozzle Cracks" was in the concurrence phase from October 31, 2001 through November 1, 2001. Those plant responses to the NRC were reviewed by several technical and administrative staff at Davis-Besse, including the Site Vice President prior to be sent to the NRC. The comments that were received by Davis-Besse reviewers were very minor.

Other evidences of a lack of understanding include the fact that the (1) 1996 PCAQ (96-0551) indicating that the RPV head may corrode stayed open for almost 3 years, and subsequent PCAQs and CRs received similar attention, (2) boric acid buildup on the RPV head was not viewed as a safety problem since it was believed that the temperature of the RPV head precluded any potential corrosion damage, (3) very little attention was given to the boric acid corrosion control program in that the procedure was not followed and critical records needed for control were not kept by engineers or others, (4) the person in charge of the boric acid program had many other duties that plant management felt were more important, (5) the plant had delayed a plant modification that would have allowed better RPV head inspections (initiated in 199X but not implemented until 2002), and (6) many plant maintenance personnel, engineers, and plant managers were aware of chronic primary system leakage and boric acid buildup on many components, but failed to determine the source or the potential consequences of the leakage. Few plant personnel were aware of critical documents issued by the NRC describing events that had occurred elsewhere, and the extent of boric acid corrosion that was possible.

3.1.6 (m) The Licensee Failed to Learn from Internal and External Operating Experience (Action: Ron)

3.1.7 (ci) The NRC Failed to Implement Adequate Programs and Guidance to Address the Implications of Alloy 600 Nozzle Cracking and Boric Acid Corrosion (Action: Joe)

- The NRC was aware of boric acid buildup on the RPV head at Davis-Besse, and was aware of the pressurizer spray valve event and its significance in 1998 ....

3.1.8 (b)The NRC Failed to Adequately Follow-Up on Relevant Generic Communications (Action: Ron)

Figure 3.1-1: Graphical Representation of Root Cause No. 1 [Proper Title TBD] - (Action: Bob/Joe/Ron; Due Date: September 6 , 2002)

3.1.9 Operating Experience at Foreign Nuclear Power Plants
The operating experience from foreign countries were evaluated only in its phase value and dispositioned as not applicable to the US plants. Even when the Oconee circumferential

cracking was observed in February 2001, the lessons from the foreign experiences were not adequately considered to possibly prevent the Davis Besse Vessel Head Corrosion.

The NRC internal trip report dated November 15, documents the NRC knowledge of Control Rod Drive Mechanism (CRDM) penetration cracks at the French Nuclear Station Bugey #3.In 1994 a study was conducted and published by Office of Analysis and Evaluation of Operational Data (AEOD) and published as NUREG/CR-6245 Assessment of Pressurized Water Reactor Control Rod Drive Mechanism Nozzle Cracking. This study documents the inspection of 4,181 CRDM nozzles at 67 overseas plants that identfied 101 penetrations with indications.

The inspection of the US plant, Point Beach#1 did not identify any indications The lack of any indication was attributed to the differences in fabrication process. The Point Beach CRDM penetrations were fabricated from tube material and heat treated at 1725 deg. F. The penetrations for the French plants were forged bars and heat treated at 1508 deg. With yield strength greater than 49.7ksi. The Point Beach nozzle material is likely to have had a lower yield strength, lower residual stresses, larger grain size, and less susceptible micro structure than Bugey unit 3. The Point Beach station had 23 years operation and no crack indication while the Bugey unit 3 had a through wall crack after 10 years of operation. The NUREG conclusions mentions the possibility of circumferential crack propagation and rod ejection but possibility is not considered to happen within the current licensing period. The axial cracks were considered not to grow through-wall because of the comprehensive axial stress present in the front of the flaws. A conservative time for the hypothetical through-wall crack was estimated to be six years. The conclusions recognized the use of N-13 leak monitoring system capable of detecting 0.001 gpm from the reactor coolant system.

In response to the PWR Owners Group submittals integrated by Nuclear management & Resource Council (NUMARC), On November 19, 1993, the Office of the Nuclear Reactor Regulation, issued a safety evaluation report (SER) concluding that there was no immediate safety concern for cracking of the CRDM penetrations The SER noted that NUMARC submittal did not address the Bugey-3 flaw, that was oriented at 30 deg. off the vertical axis or a circumferential flaw at Ringhals and indicated the need for a later assessment on these flaws.

While NRC conclusions alleviated immediate safety concerns on the basis that the cracks would noticeably leak prior to flaw size reaching unstable dimensions, the French regulatory agency proceeded with an aggressive CRDM penetration inspection program, capability to detect small reactor coolant leaks, design of a device to prevent rod ejection, and minor reactor internal modifications to reduce the under-head temperature. The details of the French experience in this area was published in the Proceedings of International Symposium on Pant Aging and Life Predictions of Corrodible Structures on May 15-18 1995 under the title Status of Alloy600 Components Degradation By PWSCC in France: Incentives and Limitations of Life Predictions as Viewed by a Nuclear Safety Body.

Susceptibility Modeling Inconclusive

The French experience further concluded that crack susceptibility modeling has significant limitations that make it impractical to perform any credible prediction. Some of the influencing factors are namely 1. The incapability to know the bulk residual stresses and the values are often estimated to the elastic limit of the semi-manufactured product. 2. Unknown stresses introduced through final finishing like straightening, reaming, machining, cold working etc., that

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are not sufficiently documented, 3. Influence of dimensional changes and deformation in relation to the initial conditions, 4. Disproportionate coupling to time and temperature based on the vessel cracks experienced at Blayais at an estimated temperature of 289 deg.C. 5. Difficulty in measuring the actual internal wall temperature, 6. The susceptibility difference between heat to heat and batch to batch due to variations in thermo-mechanical processes and carbon content. 7. Intrinsic scatter of time to PWSCC initiation exhibited by identical specimens of Alloy 6000.

Crack initiation were found in new pants like Cattenom #2 after operating time of 36,000 hours while Fessenheim #2 did not have any cracking after 107,000 hours of operation. Based on these factors, the French predictive model that was revised several times and subsequently concluded that modeling is impractical, if not misleading to prioritize inspections or maintenance. The regulators required in principle avoidance of a through wall longitudinal crack in the next fuel cycle. Therefore, the inspection program established had an eddy current inspection even in the absence of any indication. Vessel head visual inspection with insulation removal was required in every outage from the early nineties When indications were observed, eddy current and UT inspection was required more frequently. The vessel head replacement was an economical decision by the utilities in light of the more frequent volumetric examinations required when indications are observed.

In spite of the discovery of the circumferential cracking identified CRDM penetrations at Oconee Unit #3 in February 2001 and two circumferential cracks at Oconee Unit #3 in April 2001, the NRR remained contented with inspection requirements involving a vessel head visual examination that did not require the removal of the insulation or a thorough cleaning of the region for collecting any trend information. The foreign experience in dealing with circumferential cracking was not explored even at this point.

Recommendations for NRC: Establish a central operating experience group that remains cognizant of foreign operating experience and US experience to realize the benefits of shared knowledge.

Recommendations for Industry: US industry organization needs to establish a forum to interact with their counterparts in other countries for benefitting from the shared knowledge

3.2 The Licensee Failed to Ensure That the Source of Previously Identified Boric Acid Deposits on the Reactor Pressure Vessel Head Was Promptly Identified and Corrected

(Brief Summary of Root Cause and Supporting Conclusions)

3.2.1 The Licensee Failed to Adequately Address Long-Standing Reactor Coolant System (RCS) Leaks

3.2.1.1 Detailed Discussion

Reactor coolant system leakage at Davis-Besse was historically low and rarely greater than 20 percent of the 1 gpm Technical Specification limit for unidentified non-pressure boundary leakage. One exception was the period from October 1998 to May 1999, when a modification to the pressurizer relief valve discharge piping was installed that resulted in unquantified pressurizer safety valve seat leakage to be released to the containment atmosphere. Several small non-pressure boundary RCS leaks had occurred during the 1990s that the team concluded contributed to an acceptance on the part of the licensee that RCS leaks were a normal condition of operation. Since RCS pressure boundary leakage is indistinguishable from non-pressure boundary leakage without inspection, failure to adequately address and eliminate small non-pressure boundary leakage conditioned the staff to assume that leakage was not from the RCS pressure boundary.

As symptoms of RCS leakage became more prevalent from 1998 to 2002, equipment required to be operable by the Technical Specifications was affected. This equipment included the containment air coolers (CACs) and portions of the RCS leakage detection system (gaseous and particulate radiation monitors). Operability of these systems was required for continued plant operation. As the performance of these systems became degraded or inoperable, conditions were corrected to restore system performance and prevent a Technical Specification-required plant shutdown, but the cause of the condition (RCS leakage) was not corrected. Neither was it determined whether RCS pressure boundary leakage was present.

Some examples of RCS leakage sources included the following:

- <u>Reactor Vessel Head Vent Leakage</u>

  The Davis-Besse reactor vessel head vent design consisted of a hard pipe connecting the reactor vessel head to the No. 2 steam generator and was first installed in the 1988 refueling outage (RFO 05). The head vent pipe has a bolted, flanged connection at the reactor vessel head and the steam generator and is required to be removed from the reactor vessel head during each refueling outage to allow removal of the reactor vessel head.

  During the 1990 refueling outage (RFO 06), leakage and corrosion was identified at the steam generator connection and documented in PCAQR 90-0051. The gasket was replaced and the joint did not exhibit any leakage during the next operating cycle.

  In February 1992, the licensee began to investigate elevated RCS leakage and during a brief plant shutdown on March 1, 1992, identified that the connection at the No. 2 steam generator was leaking. The licensee and NRC senior resident inspector noted that the CAC coils were also coated with boric acid. The team interviewed the NRC resident inspector at the time, who recalled that the CAC coils were easily cleaned with demineralized water. The licensee evaluated the boric acid fouling condition of the CACs in PCAQ 92-0072, concluding that they were still capable of performing their post-accident containment cooling function. The team concluded that the licensee's engineering evaluation conclusion that post-accident air flow and would clear boric acid buildup from the CAC coils lacked rigor. The licensee continued to operate with the leaking head vent connection until the following refueling outage in March 1993 (RFO 08). The licensee initiated PCAQ 93-0098 to document evaluation of the condition and implemented Modification 92-0004, "Repair of Reactor Head Vent Line," during the outage to improve the joint design. The modification was inspected during an NRC modifications inspection documented in NRC Inspection Report 50-346/92018. The NRC resident inspector recalled from the inspection that there was 1 1/8-inch wastage of base metal due to the leak that had to be repaired.

- RCS Instrumentation Nozzle Leakage

  Several examples were noted during the team's review of cases of RCS hot and cold leg instrumentation leaks. The RCS resistance temperature detector (RTD) thermowell leakage boundaries consisted of two types: 1) a gasket between the thermowell and thermowell boss compressed by the thermowell nut, and, 2) a threaded and seal welded thermowell joint. Both joint types had historically leaked during operation and required repair during outages. Both are the subject of a restart project modification to prevent future leakage.

- Control Rod Drive Mechanism (CRDM) Flange Leakage

  As described earlier, the Babcock and Wilcox CRDM design contains a bolted flanged connection to the reactor vessel head nozzles. This connection had been known to leak and had been documented in correspondence with the NRC staff. For example, in 1989 Arkansas Nuclear One (ANO) - Unit 1 identified significant degradation of a CRDM flange assembly from boric acid corrosion and reported this to the NRC in Licensee Event Report 50-313/89-043. Corrective actions at ANO included replacing the CRDM nozzle flange gaskets with an improved design over a three-cycle replacement campaign No additional leaking CRDM flanges had been identified at ANO following the 1989 event. Davis-Besse similarly replaced CRDM nozzle flanges over a four-cycle replacement campaign but had continued to identify leaking CRDM flanges through the 2000 refueling outage (RFO 12).

  The Babcock and Wilcox Owners Group acknowledged to the NRC staff that CRDM flange leaks were a known problem. In its June 8, 1993, submittal to the NRC staff on the subject of potential CRDM nozzle cracking, NUMARC forwarded copies of safety evaluations from each of the PWR owners groups evaluating the subject. The Babcock and Wilcox Owners Group safety evaluation stated that: "Leakage of B&W-design flanges has previously been experienced, and visual inspections of the RV head area have been implemented so that flange leaks can be identified and repaired as soon as possible." And, "At each of the B&WOG utilities plant's, a walkdown inspection of the RV head has been implemented in response to NRC Generic Letter 88-05. As mentioned earlier, CRDM gaskets have been known to leak; thus, the walkdown

Inspection includes visual inspection of the gasket area during every refueling outage (12-24 months)." The maintenance history of Davis-Besse CRDM flanges was described in the NRC's Augmented Inspection Team report of the Davis-Besse event. The team concluded that the ongoing nature of CRDM flange leaks at Davis-Besse helped condition the licensee to expect that any RCS leakage in the head area was from CRDM flanges. The tolerance for the accumulation of boric acid on the head from these leaks prevented the capability to perform an inspection to confirm that no pressure boundary leak existed.

During RFO 12, Condition Report 00-1037 was initiated to document that boric acid accumulation was identified on the reactor vessel head and on top of the thermal insulation beneath the CRDM flanges. As part of the response to the condition report, the RCS system engineer evaluated the boric acid deposits on the head and if the source was from CRDM flange leakage. There were 5 CRDM flanges that were initially identified as having possible leaks. Four of the flanges had positive signs of leakage, however, for flange G9 the engineer stated, "Since the boron is evident only under the flange and not on the vertical surfaces, there is a high probability that G9 is a leaking CRD". CRDM flange G9 corresponds to CRDM nozzle 3 which had through-wall cracks identified in RFO 13.

There was no apparent follow-up to the high probability of the leaking CRDM nozzle during RFO 12 or any other time.

In an interview with the team, the system engineer stated that he never meant nor intended to imply there was a question of CRDM nozzle cracking. He said that if they had ever had an indication that nozzle cracking had occurred then everyone would have recognized the significance of the situation and would have properly deposited the item. However, the system engineer could not provide a reasonable explanation of the specific wording in the condition report regarding *"there is a high probability that G9 is a leaking CRD"* and how this wording could mean something other than the obvious meaning.

- Leakage of Pressurizer Spray Valve RC-2

As described in NRC Inspection Report 50-346/98021, during the 1998 refueling outage (RFO 11), pressurizer spray valve RC-2 was found to have packing leakage which caused significant boric acid corrosion of the valve yoke. Upon plant startup, packing leakage resumed and was evaluated as acceptable. Repetitive containment entries were made to monitor the leak. Although the plant had been shutdown in June 1998 following a tornado event and twice in July for steam generator cleaning, the licensee did not repair the leak, other than to install a Furmanite leak sealant injection rig on July 24. During subsequent containment entries body-to-bonnet nuts were missing. During an unplanned shutdown in October 1998, some body-to-bonnet studs and nuts were found to have been installed with the incorrect material. This licensee reported this event to the NRC in Licensee Event Report 50-346/98009 and it resulted in the issuance of a Severity Level III violation on August 6, 1999.

- Leakage of Letdown Cooler Isolation Valve MU-1A

As described in NRC Inspection Report 50-346/98018, the licensee identified that

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letdown cooler 1-1 isolation valve MU-1A had a packing leak while trying to identify sources of RCS leakage in December 1998. The licensee's plans to address the leakage were limited to the packing leak. NRC inspector prompting was required for the licensee to investigate whether body-to-bonnet stud conditions similar to that experienced with pressurizer spray valve RC-2 existed When insulation was removed, a body-to-bonnet leak 270 degrees around the sealing surface was identified. The licensee then took actions to minimize the leakage. The fastener materials for this valve were found to be correct and there was no boric acid corrosion of the valve components The team concluded that the licensee's initial plans to investigate and correct this source of RCS leakage were poor. They were minimal in scope to assess the extent of condition, given the recent experiences obtained with Valve RC-2.

- Leakage from Pressurizer Relief Valve Discharge Piping

In 1997, engineering personnel documented in PCAQ 97-1518, a potential concern that pressurizer relief valve nozzles could be overstressed if only a single rupture disk were to burst. Each relief valve had two rupture disks in its discharge pipe which would discharge to containment atmosphere if the safety valve lifted. A drain line between each relief valve and its set of rupture disks transported relief valve seat leakage to the quench tank. To address this concern on an interim basis, Temporary Modification 98-0036 was installed during an outage in October 1998. The temporary modification consisted of cutting open the rupture disks and severing the drain lines. This would prevent the hypothesized eccentric nozzle loading and overstress condition.

Prior to installation of the modification, any relief valve seat leakage would be counted as "identified" RCS leakage, because it was directed to the quench tank and accounted for in RCS inventory balance calculations. With the modifications installed, any seat leakage would discharge directly to the containment atmosphere and the resulting RCS inventory loss would be "unidentified" RCS leakage. The team reviewed the safety evaluation for the temporary modification package, which stated that, "Any safety valve leakage will be fluid from the Pressurizer steam space. The leakage will result in a dispersion of dry boric acid crystals to the containment atmosphere with the potential for a lesser amount of liquid dripping on the mirror insulation on top of the Pressurizer that would evaporate and result in a dry residual of boric acid on the mirror insulation. Those conditions do not pose an increased risk for boric acid corrosion for any carbon steel components; i.e., the Pressurizer head." The team concluded that the technical justification provided for why boric acid corrosion of nearby components was not a concern was weak.

During several team interviews with plant staff, the pressurizer relief valve modification was cited the most plausible source of RCS leakage that was considered the cause for CAC fouling and RCS leakage detection system radiation monitor filter fouling in 1998-1999. The team concluded that it was reasonable to assume that the relief valve seat leakage to containment was a contributor to increasing unidentified RCS leakage, however, as discussed in Section 3.3.1.1, the boron concentration in this contributor to RCS leakage (pressurizer steam space) may have been significantly less than the nominal RCS boron concentration and may not have been the significant contributor it was assumed to be for CAC and radiation monitor filter fouling. Nevertheless, it was an example the licensee's tolerance for RCS leakage in containment.
The temporary modification was removed during the May 1999 midcycle outage after

further engineering analysis concluded that the eccentric loading concern was not substantiated.

The team reviewed licensee activities to identify sources of RCS leakage in containment. Radiation work permit records indicate that online containment inspections were performed to identify leakage sources in 2000 and 2001. No specific radiation work permit for RCS leakage identification activities was initiated in 1999. The team reviewed the procedure used when performing containment entries. Procedure DB-OP-01101, Containment Entry, Revision 00, step 6.2.7, states, "Proceed with entry assuring the group remains together at all times paying close attention to varying dose rates and other abnormalities such as; water on floor, steam leaks, excessive valve packing or pump seal leaks, unusual or high radiation dose rates, noise, etc." The team noted that the procedure did not specifically identify boric acid identification which would enhance sensitivity to boric acid on components during containment entries.

The team reviewed impact of RCS leakage on other technical specification-required systems. The principal items of focus were the CACs and RCS leakage detection system radiation monitors. However, other equipment in containment was affected by RCS leakage and requires additional assessment by the licensee and NRC prior to plant restart. Examples include consideration of the effects of boric acid on electrical cables, other piping inside containment, and the containment liner.

RCS Leakage Detection Systems

The Davis-Besse Safety Analysis Report Section 5.2.4, "Reactor Coolant Pressure Boundary Leak Detection System," identified that the RCS leakage detection system include the containment atmosphere particulate radioactivity monitoring system, the containment sump level/flow monitoring system, and the containment atmosphere gaseous radioactivity monitoring system. The systems are designed to meet the regulatory positions of NRC Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973. Technical Specification 3.4.6.1 identifies the limiting condition for operation of these systems. The bases for these systems is to provide means to detect and monitor leakage from the RCS pressure boundary. The technical specifications also prohibit operation with any RCS pressure boundary leakage, and an immediate plant shutdown is required if any RCS pressure boundary leakage is identified.

Technical Specifications affecting RCS leakage detection systems were amended twice during the 1990s. License Amendment No. 180 was issued on September 9, 1993, and allowed use of the containment gaseous rad monitoring systems as an alternative means of detecting RCS leakage. License Amendment No. 234 was issued on November 16, 1999, and relaxed the requirement for the number of operable leakage detection systems and removed an immediate shutdown action requirement unless all three RCS leakage detection systems were inoperable.

The License Amendment Request (LAR) for Amendment No. 234 was submitted for NRC staff approval on July 26, 1999. The team noted that this submittal correlated in time to shortly after an increase in frequency of RCS leakage detection system radiation monitor filters began. The LAR contained no information to imply that there was a material condition problem with the containment air radiation monitors. Rather, the LAR was part of a larger request to move some Technical Specification-required systems to the Technical Requirements Manual (TRM) and for the RCS leakage detection system technical specification system to reflect the Babcock and Wilcox Improved Technical Specifications (ITS). The LAR was a straightforward request to implement NRC guidance for removal of systems from the technical specifications to the TRM or implementation of line-item TS Improvements to match the Babcock and Wilcox ITS. Minimal NRR technical review was required.

During the review period prior to issuance of Amendment No. 234, Iron oxide was also found on radiation monitor filters and HEPA filters were installed in containment to filter the containment atmosphere. From interviews with licensee and NRC personnel, the team determined that the RCS leakage detection system problems were not considered during NRC staff review of the LAR.

Issuance of Amendment No. 234 had the benefit to the licensee of eliminating the previous 6-hour shutdown action statement entry requirement if one train of radiation monitors (gaseous and particulate) became inoperable due to filter fouling while the other train of gaseous and particulate radiation monitors was out-of-service for any reason. This had occurred on at least two occasions prior to issuance of Amendment No. 234.

The team reviewed performance of the RCS leakage detection system and noted that each train of radioactivity detector RCS leakage monitors became inoperable many times (hundreds) because of low air flow or saturated detector conditions from 1998 to 2002. The team concluded that the radiation monitor RCS leakage detection systems had lost their usefulness by the licensee for meeting their design function, i.e., RCS pressure boundary leakage detection.

The team noted from review of control room logs that on some occasions, the radiation monitor RCS leakage detection system sample points were changed from their "normal" sample collection points (top of the D-rings) to their "alternate" sample collection points (containment dome and personnel hatch). This reduced the frequency of required filter changeouts but appeared to the team to reduce the effectiveness of the monitoring systems from performing their design function.

Some condition reports the team considered noteworthy were: Condition Report 1999-1300, which identified the accumulation of iron oxide on filters. Its corrective actions included the temporary installation of the HEPA filters inside containment (which the team concluded only addressed the symptoms of the condition) and the plan to perform an RCS walkdown during RFO 12 to look for leaks. Condition Report 2001-1110 which requested a sample point change and Condition Report 2001-1822 written about the high frequency of filter changeouts and that boric acid was present. It stated, "Currently we still have a small RCS leak in containment. This is indicated by the boron deposits on the clogged filters. Our plan is to repair the small RCS leak during the upcoming refueling outage thus eliminate the necessity of frequent filter changes. Currently the criteria for filter change is either low flow alarm of 1.5 scfm or detector to go into saturation. ... chemistry satisfied with current replacement frequency (2-7 days). Plant engineering does not recommend any additional compensatory measures." None of the above condition reports addressed the possibility that the RCS leakage detection system was actually detecting an RCS pressure boundary leak.

Each radioactivity detector RCS leakage detection system train also included a radioactive iodine monitor. This monitor was not required by the technical specifications and was not discussed in the Safety Analysis Report or other licensing basis document. However, this monitor was most prone to filter fouling and removing it from service for maintenance required removing the technical specification monitors of that train at the same time. The licensee

Installed Temporary Alterations 01-0018 and 01-0019 to eliminate the iodine monitor from the system on November 2, 2001. The team concluded that removal of this monitoring system, although it was not required, was another example of the licensee tolerating RCS leakage without adequate assessment of its source.

Containment Air Coolers

The CACs provide both normal and post-accident heat removal from the reactor building. There are three units, (two independently powered and cooled trains and a "swing" unit). The CACs share a common discharge plenum. Each CAC has an inlet temperature instrument. The average of the inlet temperature of the operating CACs is required by Technical Specification 3.6.1.5 to not exceed 120 degrees F. There is a pressure instrument in the inlet plenum which provides an indication of the differential pressure across the CAC coils. A decreasing value was an indication that CAC coils were becoming fouled and their heat transfer capability was reduced. As discussed previously, CAC fouling with boric acid had been recognized as a symptom of RCS leakage in 1992 when the reactor vessel head vent joint was found leaking. No additional cases of CAC fouling were identified until 1997. During review of station log entries, the team identified that on May 22, 1997, during the main transformer forced outage, personnel on tour in containment noted boric acid buildup on the inside of the incore instrumentation tank and on CAC No. 2. The team was unable to determine what, if any, corrective actions were taken in response to this condition. The next documented case of CAC fouling the team found was when the licensee initiated PCAQ 98-1980 on November 12, 1998. The licensee had observed that indicated CAC plenum pressure had been decreasing from 3" w.g. in early September to 2.0" w.g. on November 12. Operations documented that the condition was reviewed with the system engineer and that the CACs remained operable. A reactor building entry was made on November 14 for further inspection and it was observed that a thin, loose powdery buildup of boric acid was present on all cooling coil surfaces of the operating CACs. The boric acid was noted to be easily removable with water spray from a squeeze bottle. A team of personnel cleaned the CACs on November 18, 1998. From review of station log entries, the team observed that personnel cleaned the CACs an additional 27 times from November 1998 through May 2001. Through interviews with station personnel, the team learned that CAC plenum pressure was monitored by the system engineer, who would initiate maintenance tasks to have the CACs cleaned as plenum pressure approached an administrative limit of 1.4" w.g. The team reviewed CAC plenum pressure data and noted that on occasion, CAC plenum pressure decreased below the 1.4" w.g limit. The licensee stated that plenum pressure limit was a guideline only for initiating cleaning and that the CACs were operable based on the engineering evaluation discussed earlier for the 1992 CAC fouling event. The team noted that on several occasions, primary containment temperature exceeded the 120 degrees F limit of Technical Specification 3.6.1.5, which required that the condition be corrected in 8 hours or place the unit in hot standby in the following 6 hours. However, these occasions occurred typically in the summer months when service water temperature was warmer and CAC testing activities were being performed. There were no cases identified where containment temperature exceeded 120 degrees F and the necessary corrective action to exit the technical specification action statement was CAC cleaning. The team did not attempt to perform a detailed study of the correlation between CAC cleaning and containment temperature, but qualitatively concluded that boric acid fouling of the CACs did reduce their heat removal capability during normal operation.

The cleaning mechanism employed was a pressure washer using a kerosene fueled heater to heat demineralized water to assist in flushing the accumulated boric acid through the CAC coils and into the air plenum. During later CAC cleanings, the licensee switched to using an electric heater as the heat source for the water spray. The team requested a copy of the fire protection evaluation for acceptability of the equipment in containment that it did not pose a potential fire hazard that could adversely affect safe shutdown capability. The team was informed that fire protection engineering personnel were consulted about the use of the kerosene-heated cleaning equipment prior to first use and that a hot work permit was required during the cleaning activity. However, no formal fire protection engineering evaluation for use of the equipment inside the reactor building had been performed. From review of station logs, the team noted the following fire protection-related CAC cleaning entries: On April 10, 2000, during CAC cleaning during RFO 12, operators recorded in the log, "Received fire alarm in containment... no indication of a fire exists and a kerosene steam cleaner is being used to clean the CACs." On May 30, 2001, during online CAC cleaining, operators recorded in the log, "We will continue to perform the fire watch of containment by verifying stable CAC inlet temperature because access to containment will be limited." The team concluded that remote monitoring of containment temperatures to detect fire was an inadequate substitute for a locally-staged hot work fire watch person with a fire extinguisher.

The team concluded that online CAC cleaning activities had become a routine occurrence, almost as if it was a preventive maintenance task. The system engineer informed the team that as soon as the CACs were cleaned, he would initiate another material deficiency tag to start the planning process for the next required cleaning CAC cleaning activities even became a factor in scheduling other maintenance tasks. For example, the station log for December 29, 1998, identified that instrumentation and controls technicians had made a containment entry for a level transmitter maintenance task. The associated log entry stated that the recalibration of the instrument they had worked on would be scheduled to occur during the next containment entry for CAC cleaning. Containment entries for CAC cleaning had become so routine that other maintenance tasks would be planned around them.

As exemplified by the chronic nature of the CAC cleaning and radiation monitor RCS leakage detection system problems, these symptoms of RCS leakage became so much a part of the norm of everyday plant operation that the underlying causes of the condition were not corrected.

3.2.1.2 Recommendations

3.2.1.2.1 Recommendations for NRC

3.2.1.2.2 Recommendations for Industry

Section 3.2.2

3.2.3 The Licensee Failed to Adequately Implement Owners Group and Other Industry Guidance

3.2.3.1 Detailed Discussion

Opportunities existed for the licensee to implement Owners Group and other industry guidance that could have resulted in the earlier detection of reactor vessel head penetration cracking.

Examples of this information included: 1) the 1993 safety evaluations performed by the Babcock and Wilcox Owners Group (B&WOG) and NRC regarding vessel head penetration cracking, 2) the 1995 Electric Power Research Institute (EPRI) Boric Acid Corrosion Guide Book, and, 3) the vendor-proposed access opening modification to the reactor vessel support structure.

Correspondence between the NRC and PWR Owners Groups on CRDM nozzle cracking

The NRC staff recognized that cracking of A600 reactor vessel head penetrations was a potential safety concern in the early 1990s Meetings were conducted with the individual PWR owners groups and NUMARC to address the issue. A meeting was conducted on May 12, 1992, between the NRC and the B&WOG Materials Committee. This meeting discussed the B&WOG's efforts at reviewing the A600 nozzle cracking issue at both foreign and domestic nuclear plants. Another meeting was conducted on March 3, 1993, between the NRC and the NUMARC Ad Hoc Committee for A600 Nozzle Cracking. The NRC requested that each PWR owners group, through NUMARC, provide a safety evaluation to document why no unreviewed safety question existed for A600 reactor vessel head penetration cracking.

The B&WOG documented its safety evaluation report in Report BAW-10190P, "Safety Evaluation for B&W-Design Reactor Vessel Head CRD Mechanism Cracking," dated May 26, 1993. This report was forwarded to NUMARC for submittal to the NRC staff with the compilation of each PWR owners group safety evaluation. The NRC staff responded with a safety evaluation issued on November 11, 1993. The team reviewed these documents and includes the following noteworthy quotations:

From the cover letter forwarding Report BAW-10190P:

> Inner nozzle cracks are expected to be axial.... Once a crack initiates it will take a minimum of six years for the flaw to propagate through wall.... If a crack propagates through wall, above the nozzle to head weld, leakage is expected and a large amount of boric acid deposition is expected.... Once boric acid deposition occurs from leakage, wastage of the reactor vessel head can initiate. Based on predicted crack sizes and leakage rates, it is predicted that wastage of the reactor vessel head can continue for six years before ASME code limits are exceeded. However, the B&WOG utilities have developed plans to visually inspect the CRDM nozzle area to determine if boric acid deposition is occurring as a result of a through-wall crack. This inspection is part of the inspections implemented by Generic Letter 88-05.
>
> PWSCC for CRDM nozzles does not present a near-term safety concern If a through-wall crack occurs, the boric acid deposition expected is detectable by the current GL 88-05 inspections.

From Report BAW-10190P.

> General Corrosion Damage to the RV Head
>
> Corrosion to the RV head is a concern that has previously been addressed. Leakage of B&W-design flanges has previously been experienced, and visual Inspections of the RV head area have been implemented so that flange leaks

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can be identified and repaired as soon as possible. Primary water that exits from a leaking flange quickly flashes to steam, leaving behind a "snow" of boric acid crystals. Exposure of the RV head to the dry boric acid crystals resulting from this type of leak has not resulted in wastage of the RV head... it is expected that coolant leaking from the CRDM penetration will flash to steam quickly, as in the case of flange leakage described above, leaving only dry boric acid crystals on the surface of the head... The RV head, therefore, is not expected to corrode from boric acid "snow" resulting from a leaking CRDM nozzle.

The wastage analysis shows that safe operation of a B&W-design plant will not be affected for a minimum of 6 years.

Accumulation of Boric Acid Crystals

It is very unlikely that this type of accumulation would continue undetected with regular walkdown inspections of the RV head area. If the crystals remain hidden by the RV insulation, the insulation will begin to bulge as a result of this accumulation of crystals.... the detection of boric acid crystals on the RV head would certainly identify the existence of a leak.

B&WOG Utilities' Inspections

The B&WOG utilities have developed plans to visually inspect the CRDM nozzle area to determine if through-wall cracking has occurred. At each of the B&WOG utilities plant's, a walkdown inspection of the RV head has been implemented in response to NRC Generic Letter 88-05. As mentioned earlier, CRDM gaskets have been known to leak; thus, the walkdown inspection includes visual inspection of the gasket area during every refueling outage (12-24 months). Enhanced visual inspection of the CRDM nozzle areas has also been incorporated. If any leaks or boric acid crystal deposits are located during inspection of the RV head area, an evaluation of the source of the leak and the extent of any wastage will be completed.

Unreviewed Safety Question Conclusions

Wastage assessment determined plant can operate at least six years with significant leakage without impacting plant safety. ... leakage will have been detected... Inspections for wastage at the CRDM nozzle and head locations are completed during every refueling outage (12-24 months), so undetected leaks at this location will be discovered within 24 months.

Leakage would be detected before wastage could advance to a degree that would affect safe operation... wastage will be confined to the area adjacent to the leaking nozzle.

Conclusions

Visual inspections of the RV head are performed to identify and repair flange leakage.... it is concluded that general wastage of the RV head would also not occur because of a leaking CRDM nozzle. However, localized corrosion damage

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within and in the vicinity of the RV head penetration would be anticipated from a leaking CRDM nozzle... would not affect safe plant operation for at least six years.

Since inspections of the head area (for leakage and boric acid deposits) are performed each refueling outage, it is unlikely that a leak will go undetected for a period of six years. Calculations show that approximately 55 pounds/year of boric acid would be associated with leakage from a crack 0.5 inches in length. As the crack grows in length to 2.0 inches, the associated leak rate increases and approximately 8,403 pounds/year of boric acid would accumulate within the RV head area. Therefore, the increased leak rate will eventually lead to detection of significant boric acid deposits.

It is therefore concluded that PWSCC of Alloy 600 CRDM nozzles in B&W-design plants does not constitute a safety concern and that excessive wastage of the RV head will not occur before leakage is detected either by visual observations in accordance with utility responses to GL 88-05 or the plant leakage detection systems.

From the November 11, 1993, NRC safety evaluation of the NUMARC submittal of the PWR owners group safety evaluations:

...catastrophic failure of a penetration is extremely unlikely. Rather, a flaw would leak before it reached the critical flaw size and would be detected during periodic surveillance walkdowns for boric acid leakage pursuant to Generic Letter 88-05. However, the staff recommends enhanced leakage detection by visually examining the reactor vessel head until either inspections have been completed showing absence of cracking or on-line leakage detection is installed in the head area.

B&WOG estimates 10 years from the time a flaw initiates on the inside diameter of a CRDM penetration until a leak appears. Once a leak starts, B&WOG concluded it would take 6 years before enough corrosion would occur to reduce wall thickness of the reactor vessel head to below ASME code minimums, and that this amount of leakge would be detected during surveillance walkdowns

PWSCC does not create an immediate safety issue as long as any leakage is corrected.

Leakage at less than 1 gpm would be detectable over time based on boric acid buildup as noted during periodic surveillance walkdowns. Although NUMARC has proposed, and the staff agrees, that low level leakage will not cause a significant safety issue to result, the staff determined that NUMARC should consider methods for detecting smaller leaks to provide defense-in-depth to account for any potential uncertainty in its analysis.... The staff notes that small leaks resulting from flaws which progressed through-wall just prior to a refueling outage would be difficult to detect while the thermal insulation is installed. Although running for an additional cycle with the undetected leak would not result in a significant safety issue, the NUMARC should consider proposing a method for detecting leaks that are significantly less than 1.0 gpm, such as the

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- installation of on-line monitoring equipment

From the above documentation review, the team concluded that the NRC staff based its conclusion that no unreviewed safety question existed for the A600 CRDM penetration cracking issue based on *de facto* commitments made by the B&WOG on behalf of its member utilities. These commitments included:

- Generic Letter 88-05 Inspections of the RCS would include the reactor vessel head penetrations
- enhanced visual inspections of the reactor vessel head would be performed
- CRDM flange leakage would be identified and corrected
- boric acid evaluations would be performed for any identified leaks
- boric acid would be removed upon detection because of the potential for wastage

The team concluded that the basis of the B&WOG safety evaluation regarding identification of nozzle leak corrosion-induced wastage was dependent upon CRDM flange leakage being identified and corrected each outage. In order to determine if nozzle leaks occur, any CRDM flange leakage on the head must be identified and cleaned. As discussed previously, CRDM flange leakage at Davis-Besse was an ongoing maintenance problem, some flange leaks were not repaired after they were identified, and boric acid accumulation from flange leaks was not completely removed from the reactor vessel head which prevented the ability to inspect the base metal for signs of wastage.

The team also concluded that the NRC staff recommendation regarding enhanced leakage detection via visual head exams or installation of on-line leak detection systems in the head area was an ineffective mechanism for providing assurance that CRDM nozzle cracks were promptly identified and corrected. No serious effort was made by the industry to develop and implement an on-line leakage detection system for the head area.

In a December 13, 1993, addendum to Report BAW-10190P, the B&WOG stated that they performed an evaluation of both on-line and off-line leak detection systems. The conclusions reached from this evaluation were that the Generic Letter 88-05 walkdown visual inspections of the reactor vessel head areas provided adequate leak detection capability.

No mechanism existed to ensure that owners group member utilities implemented the *de facto* commitments made to the NRC. During interviews with licensee personnel, the team learned that there was no feedback mechanism in the licensee's organization to ensure that owners group documents were reviewed by appropriate staff or that commitments made on their behalf were incorporated into the licensee's commitment tracking program and implemented into station procedures. One commitment was identified in the licensee's commitment tracking system database, A16892, relative to these issues. Commitment A16892 was simply a tracking item to ensure that the B&WOG responded to the NRC staff with its safety evaluation. It was inadequate to ensure that the bases of the B&WOG safety evaluation, accepted by the NRC staff, would be implemented at Davis-Besse. It was closed with a statement that proper visual inspection would be performed during the 1994 refueling outage (RFO 09).

PCAQR 94-0295 was initiated on March 17, 1994, when it was believed by the RCS engineer that Commitment A16892 was inappropriately closed. The PCAQ was closed on May 9, 1994, because the licensee concluded that Generic Letter 88-05 inspections of the RCS were sufficient and acceptable to the NRC for inspection of the reactor vessel head penetrations Closure documentation stated that enhanced visual inspection was an NRC recommended but was not required. Additionally, closure documentation stated, "Due to the fact that no cases of head cracks have been identified in the United States and boric acid leakage through the CRDM flanges is low, he doesn't think that there is significant risk of a crack being present. In addition, the inspection methods presently available to us are not highly reliable. Therefore, he does not believe that it is necessary to perform the inspections at this time."

The team concluded that the NRC safety evaluation's conclusion and statement regarding "enhanced visual inspection" was generic to all PWR vendors. For Babcock and Wilcox units, enhanced visual inspection was required by default because of the CRDM flange leakage problem. The Westinghouse and Combustion Engineering units did not have flanged CRDM connections that could severely leak.

EPRI Boric Acid Corrosion Guidebook

Information relevant to the identification of RCS leakage and development of an effective boric acid corrosion control program was provided in the Boric Acid Corrosion Guide Book, issued by EPRI in April 1995.

Section 6.2.2, "Methods to detect leak rates less than about 0.1 gpm," provided two specific guidelines:

- containment air cooler thermal performance as observed in coil heat transfer degradation
- consideration for monitoring the boric acid concentration in the containment air cooler condensate

Guidance was also provided, under "other potential indicators," for the assessment of high containment particulate radioactivity monitoring results.

Service Structure Access Opening Modification

This modification was originally initiated by the licensee in Request for Modification (RFM) 90-0012, on March 21, 1990. The modification included the installation of several large access openings in the service structure which would eliminate the cumbersome and difficult method of accessing the reactor vessel head penetrations via the weep holes located at the base of the service structure. The initiator's request documentation included: "Boric acid has leaked from the CRD flanges and has accumulated on the reactor head. The reactor head is carbon steel and is therefore susceptible to degradation. Install multiple access ports with closure plates in the closure head to permit cleaning and inspection of the reactor head."

This RFM was voided on September 10, 1992. The basis for voiding stated: "This modification was initiated to allow easier access for inspection of CRDM flanges and for cleaning of the reactor vessel head. Current inspection techniques using high powered cameras preclude the need for inspection ports. Additionally, cleaning of the reactor vessel head during last 3 outages was completed successfully without requiring access ports."
The service structure access opening modification was initiated again on May 27, 1994, as RFM 94-0025. The initiator's request documentation stated:

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First, there is an ongoing industry concern involving corrosion of the Inconel 600 CRDM reactor vessel nozzles. There is no access to the reactor vessel head or the CRDM reactor vessel nozzles without the installation of this modification. Second, inspections of the reactor vessel head for boric acid corrosion following an operating cycle is difficult and not always adequate. Video Inspections of the head for the CRDM nozzle issue and as a follow-up to the CRDM flange inspection do not encompass a 100% inspection of the vessel head. Third, cleaning of excessive boric acid residue from the reactor vessel head also does not encompass 100%. The size and geometry of the service structure mouse holes with scrapers and wire brushes only permits cleaning of the lower one-third of the head surface area

RFM 94-0025 was not canceled, but it was deferred on at least 11 occasions by the licensee's Project Review Group or Work Scope Committee to future outages. The team reviewed minutes recorded for these meetings and determined that the licensee's basis for deferral was that although implementation of the modification was desirable, it was not required from a safety perspective, it was not implemented at all other Babcock and Wilcox units.

The team identified the following noteworthy documentation in minutes recorded from some of the meetings and from company memoranda:

3/16/99 memo OAD-99-70050: ISE Review of Implementation Date for MOD 94-0025

The memo concluded that deferral of the access opening mod was acceptable from a technical standpoint. Also stated however, that the intent of BACC procedure NG-EN-00324 was not being met.

PRG Meeting Minutes dated 3/7/95:
Mod (L) 94-0025: Install Service Structure Inspection Openings
Comments: "Tabled. This Cycle 11R Mod was tabled at the request of R.E. Donnellon. P.K. Goyal was in attendance to answer questions. 25% of B&W plants do not have additional inspection openings at this time. R.E. Donnellon is waiting for additional information prior to concluding that the $250K cost is worth the increased degree of assurance. No other managers wanted to sponsor at this time."

WSC Meeting Minutes dated 6/15/95:
Long Range Plan/Projects Greater than $100K - Issues List
"Bob Donnellon stated that RFM 94-0025 - Install Service Structure Openings was an open DBPRG issue being held open pending further industry information/investigation concerning actual benefit. The MOD was being held as a "place holder" until resolved. This item is not being carried in the 10YSCEP."

WSC Meeting Minutes dated 2/20/97:
Mod (N) 94-0025: Install Service Structure Inspection Openings
Comments: "The January 1, 1997 DBPRG approved schedule change to Cycle 12R for long range planning purposes. Mod delayed due to no further industry information available since last reviewed by DBWSC in June 1995. This is an unapproved Mod."

Joint PRG & WSC Meeting Minutes dated 9/3&10/97:
Task 94-0025: Inst. Svc. Structure Inspec. Openings
Comments: "Project Remains Unchanged in the Long Range Plan. F.L.Swanger

explained that sections of the reactor vessel head cannot be inspected and or cleaned. This poses a risk to system main[t]ena[n]ce efforts. The committees agreed this project should remain unchanged in the Long Range Plan."

PRG Meeting Minutes dated 9/3&10/97:
Mod (L) 94-0025: Install Service Structure Inspection Openings
New Business Request for Budget Approval for 12RFO
Results: "Recommend Approval for 13R. G.R. McIntyre, Plant Engineering, and P.K. Goyal, Mechanical/Structural, were present for the discussion. G.R. McIntyre explained that the mod resolves several issues. There is less than 50% accessibility to the reactor vessel head, which does not allow for complete inspection or cleaning of potential boric acid deposits. The mod resolves PCAQ 96-0551, one of ten oldest open PCAQs. The mod also addresses plant life extension issues. It is desired to implement the mod in 12RFO to establish a baseline of potential past boric acid corrosion on the reactor head. On-going industry concern of acid leakage from CRDM reactor vessel head nozzles could be better assessed. The committee concurred that the mod should be approved but discussed various issues related to scheduling the modification in 12RFO. They recognized that the mod implementation is a ten-day duration and could be done any outage. The DBPRG concluded that the mod be forwarded to the DBWSC meeting. A Project Manager assignment was determined not to be required at this time."

WSC Meeting Minutes dated 9/17/98:
Mod (L) 94-0025: Install Service Structure Inspection Openings
New Business Request for Budget Approval for 13RFO
Results: "Recommend Approval for 13R. G.R. McIntyre and D.E. Haley of Plant Engineering, and P.K. Goyal, Mechanical/Structural, were present for the discussion. D.E. Haley explained that there is less than 50% accessibility to the reactor vessel head, which does not allow for complete inspection or cleaning. The mod resolves PCAQ 96-0551, one of ten oldest open PCAQs. The mod will address ongoing industry concerns of boric acid leakage from CRDM reactor vessel head nozzles. J.H. Lash asked what was the basis for the 13RFO schedule. J.W. Rogers responded that this issue has been around since 1994. There are no failures in the industry. G.R. McIntyre and P.K. Goyal voiced that they were comfortable with the 13RFO schedule. The RCS leakage source is known and it is not on the head. We have inspected any boric acid sitting on the head. It has been in a dry condition and corrosion attack is not an issue. They both feel that a delay in schedule to 13RFO does not add risk. However aging is a factor and the mod should be addressed. The DBWSC agreed to approve the mod for 13RFO with a budget of $250K as presented."

PRG Meeting Minutes dated 9/7/00:
Long Range Plan 2001 Update
-Select Project Reductions to meet 2001/2002 Business Plan Targets
T.J. McCrary handed out a listing of potential reductions for the Committee to consider in meeting the 2001/2002 expenditure targets....The Committee discussed the projects listed below as possible reductions to the 2001 Business Plan: ...MOD 94-0025, Install Service Structure Inspection Opening; Results: Committee recommended deferral to 14RFO with cash flow moving from years 2001/2002 to 2003/2004.
PRG Meeting Minutes dated 2/2/01:
Open Action Items
"T.J. McCrary discussed the Open Action Items report by explaining the majority of the

Action items on the list consists of assignment of Project Managers. He emphasized the importance of assigning a Project Manager not only to ensure the project is on schedule but also as a contact to issue the project funds via the new voucher system.
Results: The following Project Managers were assigned.
...A.J. Siemaszko...Mod 94-0025, Install Service Structure Inspection Openings"

The Design Engineering Manager recognized and presented the inability to inspect and or clean sections of the reactor vessel head to the joint PRG & WSC meeting September 3, 1997. However during interviews with the team, the manager stated that he did not have any recollection of the modification.

Although engineering voiced concern regarding the lack of accessibility for complete cleaning of the reactor head and the potential to better assess the CRDM nozzles, they were apparently satisfied that head corrosion was not an issue since they were comfortable with delaying the mod from RFO 12 to RFO 13. During a September 1, 1998, PRG meeting, G.R. McIntyre, Plant Engineering, explained..."There is less than 50% accessibility to the reactor vessel head, which does not allow for complete inspection or cleaning of potential boric acid deposits. ...It is desired to implement the mod in 12RFO to establish a baseline of potential past boric acid corrosion on the reactor head. On-going industry concern of acid leakage from CRDM reactor vessel head nozzles could be better assessed." Subsequently, the minutes of the September 17, 1998, PRG meeting stated that, "G.R. McIntyre and P.K Goyal voiced that they were comfortable with the 13RFO schedule. The RCS leakage source in known and it is not on the head. We have inspected any boric acid sitting on the head. It has been in a dry condition and corrosion attack is not an issue."

During the September 7, 2000, PRG meeting, RFM 94-0025 was discussed as a potential project reduction to meet 2001/2002 business plan expenditure targets and the Committee recommended deferral to RFO 14. During one interview with the team, an individual indicated that the decision to defer at this meeting was based on a future plan to purchase a new service structure to address other modifications that needed to be done. The replacement service structure would have the access openings in place.

OBF 1040 was in the OBF-to-report section matrix for this section, but I don't believe it really fits. It is reproduced here for completeness.
Davis-Besse may not have been in compliance with the FSAR update criteria of 50.71(e). In a D Lochbaum ltr of 6/19/2002, he stated that the licensee had not included analyses of safety issues performed in response to Bulletins 82-02 and 2001-01, or GLs 88-05 and 97-01. "Assuming for the moment that Davis-Besse performed the requested analyses, it appears that they did not comply with 10 CFR 50.71 paragraph (e) by incorporating information from said analyses into the UFSAR. That omission, in our view, contributed tot he repeated failures of plant workers to fully appreciate the numerous warning signs of reactor vessel head damage." This information was also provided to the 0350 panel on 6/12/2002.

Lochbaum went on to say: "UCS first raised the concern of licensees failing to adhere to 10 CFR 50.71(e) with the NRC in January 1997. The non-conformance continues unabated and contributed, in our opinion, to the near-miss at Davis-Besse. This issue appears to fall within item (b), Regulatory Process issues, of the task force's charter. We hope that the Lessons Learned Task Force examines this matter."

50.71(e) requires FSAR updates to include all analyses of new safety issues performed by or on behalf of the licensee at Commission request. Guidance for updating FSARs is contained in RG 1.181(Sept 1999), which endorses NEI 98-03 Rev 1. These two documents were developed in response to the Millstone lessons learned report issued in February 97. Development included public meetings and solicitation of public comments.

- 98-03 states "...need for UFSARs to be consistent with the plant design and operation..." (p 1)
- 98-03 states "Safety analyses are analyses performed pursuant to Commission requirement to demonstrate the integrity of the reactor coolant pressure boundary...Safety analyses are required to be presented in the UFSAR per...50.71(e) and include, but are not limited to, the accident analyses..." (pp 2 and 3)
- 98-03 quotes Supplementary Information for 50.71(e): "Submittal of updated FSAR pages does not constitute a licensing action but is only intended to provide information." (p 6)
- 98-03 guidance regarding analyses of new safety issues: "Licensees should evaluate the effects of analyses or similar evaluations performed by licensees in response to plant-specific NRC requests or NRC generic letters or bulletins. NRC-requested analyses and evaluations must be reflected in UFSAR updates only if, on the basis of the results of the requested analysis or evaluation, the licensee determines that the existing design bases, safety analyses or UFSAR description are either not accurate or not bounding or both....If the NRC-requested analyses or evaluations do not cause any of the effects, no change to the UFSAR is required." (pp 7 and 8)

- Based on the above, it is not clear if Davis-Besse was in violation of 50.71(e)
- Within the scope of the LLTF review, there is insufficient information to determine if there is industry-wide non-conformance with 50.71(e).
- The need to provide information in this regard appears to have been met by licensee responses to generic communications.
- Given the number and breadth of apparent causes for the RV head degradation at Davis-Besse, along with the availability of the technical information in response to generic communications, it does not appear likely that the absence of this information in the UFSAR contributed to the Davis Besse event.
-

NRC technical staff and OGC should review this matter further in the context of addressing lessons learned and inspection follow-up
UCS letter of 6/19/2002
10 CFR 50.71 (e)
RG 1.181 (September 1999), content of the Updated Final Safety Analysis Report in Accordance with 10 CFR 50.71(e)
NEI 98-03, Rev 1 (June 1999), Guidelines for Updating Final Safety Analysis Reports

3.2.3.2 Recommendations

3.2.3.2.1 Recommendations for NRC

3.2.3.2.2 Recommendations for Industry

Section 3.2.4

3/7

3.3 The NRC Failed to Accurately Assess the Safety Performance of the Davis- Besse Nuclear Power Station

(Brief Summary of Root Cause and Supporting Conclusions)

3.3.1 The NRC Failed to Adequately Assess the Symptoms of Reactor Coolant System (RCS) Leakage

3.3.1.1 Detailed Discussion

Numerous symptoms of RCS leakage inside the Davis-Besse containment existed from 1998 until the unit was shutdown for the 2002 refueling outage (13 RFO). While the NRC inspection effort reviewed many of these symptoms, there was limited assessment and analysis of Davis-Besse's efforts to identify and resolve RCS leakage. Inspections were performed that recognized and focused on RCS leakage, while other inspections reviewed areas which related to RCS leakage. The inspections in these related areas did not address RCS leakage as part of their assessment of Davis-Besse's performance. Many of the symptoms of RCS leakage when reviewed individually, provided minimal insights into the actual degraded condition of the reactor head. To fully assess and recognize the resulting condition of the RCS leak in containment, i.e., reactor head degradation, an integrated assessment of the symptoms was required The NRC failed to perform an integrated review the RCS leakage symptoms

For the time period of 1998 to February 2002, unidentified RCS leakage (monthly average) ranged from the normally low value of less than 0.1 GPM to a maximum of 0.8 GPM. The primary cause of the higher leak rate was a change to the pressurizer relief valve discharge piping in October 1998. Once the normal discharge piping configuration was restored in May 1999, the leak rate decreased, but values ranged between 0.1 to 0.3 GPM until February 2002.

The specific indications of RCS leakage in containment included the following:

- There was an increase in unidentified RCS leakage which could not be correlated to any specific source following restoration of pressurizer relief valve discharge piping to its normal configuration;

- The containment air cooler (CAC) experienced fouling as boric acid particles in the containment atmosphere collected on the CAC cooling fins. As the amount of boric acid fouling increased, corresponding changes in CAC plenum pressure would be seen on the remote indication in the control room. In response to changing plenum pressures the CACs were cleaned 17 times from November 1998 to May 1999. The change to the pressurizer relief valve discharge piping in October 1998 which also directed relief valve seat leakage to the containment atmosphere was viewed by the licensee as the primary cause of the CAC fouling. Eleven additional CAC cleaning were required following restoration of the relief valve discharge piping until the unit was shutdown for In February 2002. The frequency of CAC cleaning was higher during the earlier periods of the fuel cycle. This is consistent with higher concentration of boric acid in the RCS at the start of the fuel cycle and the gradual reduction of RCS boric acid over the fuel cycle.

- The containment radiation monitors also experienced fouling of boric acid particles on the filter paper. Air samples are continuously drawn from within containment, passed through a particulate filter, an iodine sample cartridge and a noble gas detector before being exhausted back into containment. The buildup of boric acid on the filters would reduce air flow to a point that filter change out was required. To accomplish this the radiation monitor was taken out of service. Prior to the boric acid fouling, the radiation monitor filters were replaced each month as routine maintenance. Starting in late 1998 the filter change outs increased to weekly, then cycled between daily to an irregular one to two week replacement interval. In May of 1999, the radiation monitor filters began accumulating a yellowish-brown material. The laboratory analysis of the material identified the presence of ferric oxide. Specifically, this analysis stated, "The fineness of the iron oxide (assumed to be ferric oxide) particulate would indicate it probably was formed from a very small steam leak."

- In each of the 1996, 1998, and 2000 refueling outages a visual inspection of the reactor head identified an accumulation of boric acid. A corrective action document was initiated for each occurrence to address the condition.

- Evidence of boric acid deposits was noted on numerous surfaces in containment. During containment walkdowns by the team, rust on carbon steel surfaces of service water piping, cable trays and covers, and CACs was observed. Boric acid residue was also noted on these surfaces. The amount of rust was directly related to the corrosive nature of boric acid on carbon steel. During a review of the control room log the team noted a May 22, 1997, entry which stated boric acid buildup was noted on the inside of the Incore tank and on CAC number two.

Based on the available indicators and interviews with Davis-Besse and NRC personnel it was clear to the team there was widespread knowledge of RCS leakage in containment and that the leakage persisted over a period of several years. The senior resident inspector and DRP branch chief stated in interviews they were aware of the leakage and that they engaged the licensee on their efforts to identify and resolve the leakage. During the RIII morning meeting in which plant status and issues are discussed, the branch chief would routinely mention some of the RCS leakage indicators. These included at power containment entries to clean the CACs and TS action statement entries due radiation monitor filter replacement. On occasions both trains of radiation monitors would be inoperable when one train was removed from service to change the filter and the other train experienced a low flow condition.

The NRR project manager for Davis Besse during 1999 participating regularly on the morning status calls held by the Region III staff. He recalled that boric acid buildup was discussed and that the licensee was making efforts to find RCS leaks through walkdowns, and that the licensee attributed the buildup to leaking pressurizer safety valves. Containment air cooler fouling was also discussed in the morning calls, and was a concern because of elevated containment air temperatures during the summer months. He assumed that the Region III staff were observing licensee efforts to address the issues.

Senior management in RIII did not have the same level of awareness of the indicators nor of the continuous nature of the RCS leakage in containment. In an interview one manager recalled problems with radiation monitor fouling because of the associated TS action statement entries and another manager said that he was briefed on CAC cleaning. The other managers stated they did not recall hearing about or discussing these items. The team concluded there was distinct difference in the level of knowledge on Davis-Besse RCS leakage and the indicators between the branch chief and senior regional managers.

In interviews with the resident inspectors they stated that regional managers did not provide feedback on RCS leakage or the indicators in the form of inspection guidance to the residents. The branch chief discussed RCS leakage and the indicators with the residents in an efforts to understand the licensee's position of source of leakage and their plans to resolve the leakage. In an interview the branch chief stated that during on site visits to Davis-Besse he routinely discussed RCS leakage activities with the licensee

For the period of February 13 - September 13, 1999, five consecutive resident inspector inspection reports (each covering a 6-week period) discussed inspections which related to RCS leakage. The inspections focused primarily on the April 24 - May 10, 1999 midcycle outage activities. While there was some assessment of licensee activities and the majority of reports described the RCS leakage, related conditions, such as radiation monitoring fouling, and the licensee's plans to resolve the leakage. Following the outage the inspection reports discussed the reduction in RCS leakage but recognized that radiation monitoring fouling continued to occur and that the filters had accumulated a dark colored particulate which was determined to be primarily iron oxide (a corrosion product). In the last of these inspection reports which discussed RCS leakage, the inspectors stated that the source of corrosion products was still unknown and that the licensee planned to perform thorough inspections of the containment during the next refueling outage to detect the source. In reviewing subsequent Davis-Besse inspection reports, the team found no other inspections of licensee's efforts to resolve RCS leakage. NRC Inspection Report No. 50-346/01-013 discussed a temporary modification to bypass the charcoal filters on the containment radiation monitors. This related to RCS leakage in that the filter were bypassed because of moisture clogging the charcoal. High humidity in the containment from the RCS leakage was the probable source of moisture.

Several assumption made by Davis-Besse regarding RCS leakage were questioned by the team and were considered additional opportunities for the NRC to more aggressively assess Davis-Besse efforts to address RCS leakage. Davis-Besse believed that a significant contributor to CAC fouling was leakage from the pressurizer relief discharge piping that was temporarily vented into containment atmosphere. NRC Inspection Report No. 50-346/99-004 discussed the relief valve leakage evaporating into the containment atmosphere, condensing on the CACs and degrading their performance to the point that cleaning was required every 10 -14 days. Based on leakage from the pressurizer stream space (were the relief valve are located) being at a lower boron concentration that the RCS, the team questioned how much boron acid would actually be released from relief valve leakago. It did not appear this was assessed by Davis-Besse in 1999. During the LLTF review, Davis-Besse responded to the team that some boric acid would carryover into steam at high RCS pressures that the amount would be significantly less than a RCS leak. From interviews with NRC staff and review of inspection report the team concluded this issues was not previously reviewed. Davis-Besse also believed that one of the most likely sources of RCS leakage that was causing CAC and radiation monitor fouling was CRDM flange leakage. This was based a long history of CRDM flange leakage During the 1999 midcycle outage CRDM flanges were inspected and no leakage was identified. This was not recognized by many Davis-Besse personnel in that they continued to believe CRDM flange leakage was a cause of CAC and radiation monitor fouling. Had this been understood by the licensee, increased efforts could have been taken by the licensee in 12RFO to identify the source(s) of RCS leakage.

Other inspections which dealt with RCS leakage indications or RCS systems provided the NRC with additional opportunities to engage the licensee on their efforts to resolve RCS leakage. Two inspections (NRC reports Nos. 50-346/99-002 and 01-004) reviewed radiological controls for containment entries to clean the CACs In 1999 the inspector observed one of the work crews in containment while the CACs were cleaned and discusses the boric acid deposits on the CACs from a pressurizer isolation valve. Both inspections assessed the radiological implications for CAC cleaning but did not explore the reasoning for the CAC fouling, i.e.,continued RCS leakage. Two inspection (NRC report Nos. 50-346/98-006 and 00-005) reviewed inservice inspection (ISI) related to the RCS. They were performed during the 1998 and 2000 refueling outages. The 1998 inspection observed a dye penetrant examination of a CRD housing weld and a visual examination of the reactor vessel bolt holes. The report did not mention boric acid on the head or any related issues. In an interview the inspector did not recall seeing boric acid on the reactor head or on the insulation directly below the CRDM housings. During the 2000 ISI inspection, the inspector observed ultrasonic and magnetic particle examinations on the reactor closure head to flange weld. In addition the inspector reviewed CR 2000-0781 and verified the corrective actions were appropriate. This CR described boric acid on the reactor head which prevented the visual inspection of the flange fasteners. There was no discussion in the inspection report on boric acid corrective actions for the reactor head. In an interview the inspector who performed the 2000 ISI inspection did not recall seeing boric acid on the reactor head or anything unusual about the corrective actions for CR 2000-0781. The team concluded these inspections were additional examples for the NRC to become informed of the boric acid accumulation of the reactor head and question db on their corrective actions

During interviews RIII personnel stated that at the time the RCS leakage in containment was not viewed as a significant safety issue. Factors that RIII provided to support a basis for this view included RCS leak rates being less than the TS limit and Davis-Besse providing logical explanations as to possible sources of leakage. The team noted other items which confirmed this view by RIII. These included the lack of guidance to the residents inspectors for pursuing the leakage under the inspection program; the lack of senior management's awareness of the continuing nature of the RCS leakage in containment; not performing any followup inspection in 12RFO on licensee efforts to identify and correct RCS leakage (even though a 1999 NRC inspection recognized that the source of corrosion particles in containment was unknown and reviews would be performed in 12RFO); not recommending that the PI&R Inspection in February 2001 review RCS leakage corrective actions (see Section 3.3.2); and a briefing paper to support a Regional Administrator's site visit in March 2001 stated there were currently no significant equipment concerns, but later mentioned monthly CAC cleaning.

As noted in Section 3.3.2 the senior resident inspector was aware that boric acid was discovered on the reactor head in 12 RFO. The discovery of red/ brown boric acid on the reactor head was a significant insight that the numerous and longstanding indications of RCS leakage in containment were important safety concerns that demanded NRC followup. Since this information was not passed onto the region, the opportunity for the region to factor the discovery of boric acid on the reactor head into their view on RCS leakage in containment was lost. The team believes the ability to assess relevant conditions into the overall outlook on plants issues is an extremely important function of the inspection staff. This function is even more crucial for resident inspectors who are the only NRC individuals that have access to all this type of information.

3.3.1.2 Recommendations

3.3.1.2.1 Recommendations for NRC

- Re-emphasize questioning attitude among NRC staff/management Consider this attribute in individual and organizational performance measures.
- Establish structure and expectations for management interaction with staff to followup on the types of problems that occurred at Davis-Besse
- Review refueling inspection procedure, Att 22 ???, to determine if adequate instructions and expectations for outage reviews are specified
- Emphasis to inspectors to remain aware of their surrounding when inspecting in a particular area, such as radiation protection, and the need to pass on observations to applicable personnel

3.3.1.2.2 Recommendations for Industry

- None

3.3.2 The NRC Failed to Adequately Inspect the Safety Performance of the Davis-Besse Nuclear Power Station

3.3.2.1 Detailed Discussion

The team identified shortcomings with the NRC inspection effort at Davis-Besse. These included missed inspection opportunities that related to the reactor head degradation, inaccurate inspection results, and improper implementation of the inspection program. The team reviewed inspections that were implemented under both the old NRC Inspection Manual Chapter (IMC) 2515 and the revised reactor oversight process (ROP).

Prior to April 2000, inspections at operating reactors were preformed under the guidance of IMC 2515. The majority of inspections performed under 2515 were part of the "core" program which was implemented at all reactor sites. The regions had allowances to perform "regional initiative" inspections in areas with identified or perceived licensee performance problems. In April 2000, the NRC transferred to the ROP which is more structured than the old IMC 2515 program. Under the ROP, baseline (BL) inspections are performed at all reactor sites and they constitute a very larger portion of the overall inspection effort. The ROP has supplemental inspection which are performed for problems (findings) that have greater than low safety significant. The ROP does not allow "regional initiative" inspections of lower level problems or issues that potentially could, but have not yet resulted in a significant problem. The team reviewed inspection implementation back to 1990 but the review focused on inspection activities since 1996, which correlates with the estimated time that head degradation began.

As discussed in Section 3.3.1, five reports from 1999 documented inspections related to RCS leakage. The report writeups for these inspections have limited information on inspector actions. Most of the writeups contain phrases such as, "the inspectors reviewed the licensee's efforts...," and "the inspectors reviewed licensee efforts..." but provided no other indications of specific actions that the inspectors performed. Interviews with the applicable inspectors provided no additional insights on the depth of these inspections Based on review of Davis-Besse records and interviews with Davis-Besse personnel, the team identified several relevant issues that could have been identified by a probing inspection These included an apparent lack of operability limits for CAC plenum pressure or justification that boric acid fouling would not effect CAC post accident function; no evaluation to support the use of a kerosene heater in containment to support CAC cleaning; and the temporary modification that changed the pressurizer discharge piping configuration did not address several obvious considerations associated with the change

While reviewing Davis-Besse's efforts to identify the source of RCS leakage in containment the team noted that an action plan was not developed for 12RFO. Based on limited information that Davis-Besse was able to locate for this effort, it appears that only routine outage inspections were performed to identify RCS leakage in containment. This was contrary to a corrective action specified in CR 99-1300 to issue an action plan for containment walkdowns in 12RFO to identify the source of the red/ brown boric acid deposits on the containment radiation monitor filters For the following refueling outage,13RFO, the Mode 3 containment walkdown was not performed at the beginning of the outage. The Mode 3 walkdowns were initiated in response to GL 88-05 as a means to identify containment leakage with systems at normal operating pressure and temperature. As noted above noted above, no NRC documented inspections of the Davis-Besse efforts to identify RCS leakage were performed following the 1999 inspections. Since indications of RCS leakage were continuing, the team concluded probable cause existed to perform additional inspections and that these inspections could have identified problems with Davis-Besse's efforts

Davis-Besse's corrective action program was last inspected under the 2515 core program in August 1998 per Inspection Procedure 40500, Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems. This inspection did not review any issues related to RCS leakage in containment or boric acid on the reactor head. Based on the timing of this inspection and the limited information available on these topics, the team considered this was not unexpected. The frequency of performing 40500 inspection under the core program was every SALP cycle, which for Davis-Besse was every two years. The next review of corrective action program was the Problem Identification and Resolution (PI&R) inspection in February 2001. This was performed under the ROP which required a PI&R inspection each assessment period. The first ROP assessment period was from April 2000 to March 2001. Based on the timing of the PI&R, there was a 2 ½ year gap between these corrective action inspections. In light of the ROP expectation to perform a PI&R inspection each year, the team questioned the decision to perform the Davis-Besse PI&R inspection at the end of the ROP assessment cycle verses earlier. This would have allowed a more timely review of Davis-Besse's corrective action implementation and possible recognition that efforts to locate and correct RCS leakage in containment were inadequate.
ADD SECTION FOR 40500 INSPECTION IN 8/98 DID NOT REVIEW PCAQ-0551 WHICH WAS OPEN FOR 2 1/2 YEARS WHEN GUIDANCE IN 40500 MENTIONS TO REVIEW LENGTH OF RESOLUTION. SEE IF PI7R HAS SAME EXPECTATIONS

The team identified two aspects of the 2001 PI&R inspection that warrant further discussion. Guidance for PI&R inspections is provided by IP 71152, Identification and Resolution of

Problems. The general guidance section of IP 71152, states, "Additional insights for determining appropriate samples can be obtained by region based inspectors through discussion with resident inspectors or regional inspectors who are familiar with site issues and who are familiar with the licensee's problem identification and resolution process." Routinely the DRP branch chief will provide insights to the PI&R team on problem areas that the PI&R may consider for followup review. Based on interviews with the 2002 PI&R team members and the branch chief, there were no suggestions to review any of the ongoing indicators or CRs related to RCS leakage in containment or Boric acid on the reactor head. In the interview the branch chief stated that he did not consider the RCS leakage in containment significant enough to warrant followup by the PI&R inspection. The team determined the continuous nature of the RCS leakage and the ineffective licensee corrective actions were situation that IP 71152 intended for PI&R followup and that RIII should have suggested this to the team. In determining which problems to review for corrective action implementation, the PI&R team screened previous CRs. For the Davis-Besse PI&R this was accomplished by reviewing a printout containing abbreviated CR descriptions. For CR 2000-0782 the abbreviated description was, "Inspection of the Reactor Flange indicated Boric Acid leakage from the weep holes." As noted below, the actual condition description for CR 2000-0782 provides a substantial amount of information on the type, quantity, and location of the boric acid. IP 71152 does not specify the manner in which licensee identified problems are select for PI&R review, e.g., review entire problems description verses an abbreviated description. With the large number of CR written by many licensees, reading each CR description may not be practical during a PI&R inspection. The team believes that had the complete description been used in the screening of issues, CR 2000-0782 should have been selected for PI&R review.

On August 6, 1999, escalated enforcement was taken for boric acid corrosion on 3 of 8 body-to-bonnet nuts for Pressurizer Spray Valve, RC-2 at Davis-Besse. The Severity Level III violation was for inadequate material control, carbon steel nuts were installed in lieu of stainless steel nuts, and failure to implement effective corrective action. An earlier special inspection (Report No. 50-346/99-021) of this event reviewed corrective actions, both taken and planned, for the RC-2 event. Enhancements to the boric acid corrosion procedure, NG-EN-00324, were discussed in the report. LER 1998-009-00 describe this event and two corrective action commitment that Davis-Besse made to the NRC. These included enhancements to the Boric Acid control program and training for managers and technical staff on boric acid corrosion control and lessons learned from the RC-2 event. The team noted some members of the technical staff who were involved with previous and subsequent boric acid corrosion issues did not receiving the training. Also, some weaknesses in revised procedure, NG-EN-00324 were observed. The team noted that RIII did not perform followup inspection to closeout the violation for RC-2. There were followup inspections for the LER and revision 1 to the LER, however, they did not specifically address review of the completed corrective actions discussed above. IP 92902, Followup - Maintenance, which was in effect at the time for closeout of maintenance related violations required that licensee's implementation of corrective actions be reviewed. For the RC-2 violation it is unclear if the NRC actually inspected/ reviewed corrective action implementation. In interviews with RIII managers, differing views there provided on the closeout of RC-2 violations. Some managers thought that closeout of LERs and the review performed in the special inspection were satisfactory, while other managers believed that a violation closeout should include review of corrective action implementation. The team concluded that the guidance for closeout of violation was not followed and an additional inspection of Davis-Besse's boric acid corrosion program would have provided an opportunity to identify some of the program weaknesses.

IP 62001, Boric Acid Corrosion Prevention Program, was included in Appendix B to the old IMC 2515 program which listed regional initiative inspection procedures. RIII did not use IP 62001 in the followup inspection to the RC-2 event. Based on the circumstances surrounding RC-2 and the fact that a special inspection was performed the team thought is was logical that IP 62001 should have been utilized to provide structured guidance for the inspection. While it was not clear that use of IP 62001 would have altered the positive conclusions of the special inspection on the boric acid corrosion program, it would have ensure that the review included all critical aspects of the program.

The senior resident inspector stated in an interview he was aware that boric acid was identified on the reactor during the 2000 refueling outage (12RFO) but recalled that the condition was not viewed as significant at the time and didn't require followup. In addition the senior resident inspector stated that he had reviewed the licensee's boric acid corrosion program following the RC-2 event and believed that boric acid on the reactor head would be properly resolved based on his favorable review of Davis-Besse's boric acid corrosion program. The senior resident inspector 's recollection of the condition was white boric acid crystals on the head with no indication that the quantity of boric acid was large. CR 2000-0782 documented the boric acid that was discovered on the head in 12RFO. The condition description stated, "Inspection of the Reactor Flange indicated Boric Acid leakage from the weep holes (see attached pictures and inspection record). The leakage is red/brown in color. The leakage is worst on the east side weep holes. The worst leakage from one of the weep holes is approx. 1.5 inches thick on the side of the head and pooled on top of the flange... The total estimated quantity of leakage though the weep holes and resting on the flange is 15 gallons. All leakage appears to be dry... Preliminary inspection of the head through the weep holes indicates clumps of Boric Acid are present on the east and south sides..." CR 2000-1037 was subsequently written to disposition the boric acid on the reactor head. Its description stated, "Inspection of the Reactor head indicated accumulation of boron in the area of the CRD nozzle penetrations through the head. Boron accumulation was also discovered on the top of the thermal insulation under the CRD flanges. Boron accumulated on the top of the thermal insulation resulted from CRD flange leakage." Based on the senior resident inspector's recollection of the condition of boric acid on the reactor head it is unclear if the CR descriptions were actually read. Under the ROP, Appendix D, Plant Status, to IMC 2515 provides guidance for problem identification with the statement, "Review the licensee's deficiency or non-compliance reports to became aware of safety significant problems that can be followed up through elements of the baseline program". The team concluded that the description of CR 2000-0782 should have been viewed as a potential safety significant problem and received follow up by the baseline program. Since the information regarding boric acid discovered on the reactor head in 12RFO was not passed on to the region, there not an opportunity for the region to consider the need for follow up inspection.

The team identified a positive aspect of RIII's ROP implementation, by utilizing baseline inspections to review important commitments associated with Bulletin 2001-01, . These commitments were implemented to support Davis-Besse's continued operation to February 16, 2002 (see Section ___). RIII mapped out the commitments to various baseline inspection activities, then completed the reviews during the routine 6-week inspection. The inspection results were documented in NRC Inspection Report Nos. 50-346/01-015 and 01-016.

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3.3.2.2 Recommendations

3.3.2.2.1 Recommendations for NRC

- Assess the overall PI&R guidance such that issues similar to those experienced at Davis-Besse are reviews (possible emphasis on the 3 -6 issues /years that PI&R reviews and biannual inspections). Should specific guidance be provided on the format or listing of issues that are review to determine which specific problems will be reviewed by the PI&R

- Review ROP guidance to determine if changes are needed to allow longer term followup on issues that haven't progressed to a finding. Should IFIs be allowed that would direct future inspections in areas of concern

- Emphasize through a "case study" training that inspection must probe into issues or potential problems verses reviewing licensee action and providing a status of these action in an inspection report

- Assess the need for inspection of licensees boric acid corrosion programs, similar to the actions directed by IP62001.

3.3.2.2.2 Recommendations for Industry

None

3.3.3 The NRC Failed to Adequately Integrate Davis-Besse Nuclear Power Station Safety Performance Data

Following discovery of the reactor vessel head wastage at Davis-Besse, headquarters and regional staffs considered whether to send an IIT, an AIT, or an SIT to the site. According to interviews with staff and managers, the LLTF learned that the decision was strongly influenced by risk assessment. In order to develop a risk estimate, an initiating event frequency of 0.1 was assumed, which resulted in a CDF of 1E-5, which was right between the AIT and IIT criteria (per Barrett Interview). This initiating event frequency of 0.1 was chosen as a compromised between 1 (which would have applied had there been a LOCA) and 0.01, which was the assumed initiating event frequency for failure of a CRDM tube due to circumferential cracking.

The LLTF found that there did not appear to be a solid technical basis for choosing this event frequency, nor did there appear to be explicit treatment of pressure boundary degradation in PRAs. These shortcomings question the validity of the agency's use of risk information in making regulatory decisions.

3.3.3.1 Detailed Discussion

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The NRC viewed Davis-Besse as a good performer prior to discovery of the reactor head degradation in February 2002. This view was shared by nearly all RIII interviewees, the NRR Project Managers and resident inspectors. The ROP inspection results and performance indicators (PI) also support this view in that all PIs and inspection report findings since ROP Implementation have been Green. The last SALP assessment was for the period of January 22 1995, to January 18,1997. The SALP scores were a "2" in Operations and a "1" in the remaining three areas, Maintenance, Engineering and Plant Support.

For the 3-year period between the last SALP assessment and ROP implementation in April 2000, the plant performance review (PPR) process was used to assess Davis-Besse's performance. The team reviewed all the PPR summary for this period and identified only one discussion point involving RCS leakage in containment or its symptoms. For the PPR review that ended on January 31, 1999, the "Material Condition" section of the summary mentioned that unidentified leakage was more than half the allowed value and CACs need to be cleaned on a regular basis due to boric acid buildup. No future inspections were recommended in the PPR to address this area. In the letter to Davis-Besse, dated March 26, 1999, which transmitted the PPR results, there was no mention of RCS leakage, CAC cleaning or assessment of the licensee's corresponding actions. The team concluded that the PPRs conducted from February 1997 to March 2000 failed to adequately assess Davis-Besse's performance and take appropriate regulatory responses **NEED TO VERIFY RESULTS OF PPR FOR 2/99 -3/00** Numerous plants problems related to RCS leakage in containment were known by the NRC and documented in inspection reports but were not recognized for their safety implications.

Under the ROP, assessments of plant performance are done on a somewhat informal basis every quarter and in a structured setting every 6-months. The team reviewed the summary packages for the assessments performed through December 2001. There was no mention of RCS leakage in containment, the accompanying symptoms, or boric acid on the reactor head. The ROP assessment process reviews problems (designated as "findings" by the ROP) that have a significance of Green or greater. Findings are classifies by the significance determination process (SDP) with the lowest rating being Green, very low safety significance. Under the ROP the NRC identified numerous Green finding at Davis-Besse but none dealt with RCS leakage in containment or boric acid corrosion control. The ROP assessment process also review the PIs that licensee's report to the NRC. For PIs that rise above the Green band, the NRC will engage the problem with additional inspections and regulatory interface. The PI that monitors RCS leakage would be applicable to the performance issues experienced at Davis-Besse. The Green PI threshold is at one half the TS limit for RCS allowable leakage. For Davis-Besse this value is one half GPM for unidentified RCS leakage, which was not exceeded while the ROP was in place. A noteworthy observation is that this PI would have been White in 1999 when RCS unidentified leakage reached a value of 0.8 GPM. The NRC response under the ROP would have been a supplement inspection to review the corrective actions for the root cause(s) of the condition. The NRC's assessment of Davis-Besse's performance was in accordance with the ROP guidance and was based on the findings and PIs that were available. As noted earlier, the team believes that performance issues exited at Davis-Besse which could have been characterized as finding and then could assessed by the ROP.

As noted in Section 3.3.2 the senior resident inspector was aware that boric acid was discovered on the reactor head in 12 RFO, however, this information was not provided to the region. The senior resident inspector elected to not followup on this condition. During his interview the resident inspector stated that he was not aware that boric acid was covered on the reactor head in 12RFO. An expectation for resident inspectors is that important issues are discussed between the residents to capitalize on group dynamic interaction and utilize the entire resident staff knowledge level when performing their initial assessment. Since the resident inspector was not aware of this information this interchange must not have occurred. The team recognized that resident inspectors must sort through many issues that licensee's enter into their corrective program and decided on which issues to followup on based on their importance and potential to impact plant safety. However, the team viewed the discovery of red/ brown boric acid on the reactor head following numerous and longstanding indication of RCS leakage in containment as one of the most crucial pieces of information that could have led to an earlier identification of reactor head degradation. With the senior resident inspector not following up on this issue this opportunity was lost and not passing the information onto the region prevented RIII from understanding its significance.

When reviewing why the senior resident inspector did not followup on the boric acid the reactor head it was noted that the ROP was initially implemented when 12RFO on going. In interviews, the resident inspectors mentioned that additional effort was required to understand and plan for the ROP. The team's own experience with ROP implementation recognized this factor and that some of the resident's time which previously would have been used for inspections was required for ROP startup.

The unreliability of RCS leakage detection containment radiation monitoring system due to fouling with boric acid, iron oxide, and water and Davis-Besse's numerous actions to live with condition verses resolve the root case was an example of the NRC not fully integrating all available information into its assessment. Data that was available to the NRC included:

- Several unintentional entries into 6 hour TS shutdown action statements due to both trains being inoperable at the same time.

- In May 1999, the systems were becoming inoperable so frequently due to filter clogging, that each train was to be removed from service every other day, on a staggered basis, to replace the filter as a pre-emptive measure. Some low flow alarms still occurred.

- Many Channel 3 detector (iodine) saturation alarms occurred that required filter changeouts. It was unclear from a review of the operator logs whether Channel 3 was still in saturation after the filter was changed out and the system declared operable.

- In July 1999 and April 2001 the sample points were changed from the primary location (at the top of D-rings) to the alternate location (dome or personnel hatch). While this reduced the frequency of filter changeouts, it may have also made the detection system less efficient at detecting leaks. ***(Bywater's conclusion DO we keep this thought ?)***

ab

- In August 1999 a temporary modification installed four portable HEPA filtration units in the containment in an attempt to remove the particle that were clogging the filters. This activity was later documented in NRC Inspection Report No. 50-346/99-010 was stated the HEPA units were installed to remove the corrosion product particulates in the containment atmosphere that periodically affected the operation of the radiation monitors

- In November 1999 the laboratory analysis of the material clogging the filters identified the presence of ferric oxide. Specifically, this analysis stated, "The fineness of the iron oxide (assumed to be ferric oxide) particulate would indicate it probably was formed from a very small steam leak." The iron oxide particles that were clogging the filters was discussed in NRC Inspection Report No. 50-346/99-008.

- A temporary modification was installed in January 2001 to bypass iodine monitor ***BECAUSE....*** This temporary modification was inspected by the NRC (NRC Inspection Report No. 50-346/01-013.

As noted in Section 3.3.1, many levels of the NRC were aware of the problems and actions that Davis-Besse took when dealing with filter clogging This occurred over an approximate 3-years time period. Based on interviews with involved individuals and review of applicable inspection reports the team concluded that the NRC failed to properly assess the large quantity of available data and identify the inadequate taken by Davis-Besse.

An example of the NRC not properly integrating inspection insights involved an issue discussed in NRC Inspection Report No. 50-346/98-018. The report describes a letdown cooler isolation valve, MU-1A, that was found with a packing leak during online containment search for RCS leakage in December 1998. This occurred shortly after RC-2 packing leak which corroded three of eight body-to-bonnet fasteners. Davis-Besse's corrective actions for the RC-2 event were poor. Following questioning by the NRC inspector on the initial MU-1A work scope that did not include insulation removal to check for boric acid corrosion, the work was modified to include insulation removal. When the insulation was removed a body-to-bonnet leak that encompassed about 270 degrees of the seating area was discovered. Subsequent repairs corrected the leaks. The inspection report characterized Davis-Besse's performance in a positive manner for their activities to minimize the leak. The report conclusion and executive summary comments did not capture limited initial corrective action and that NRC prompting was required to ensure adequate corrective action were implemented. While the inspectors recognized the previous problem with RC-2 and factored that into their inspection activity, the NRC failed to integrate similar performance problems into the message for this issue. Highlighting additional implementation deficiencies of the boric acid corrosion program would have provided greater emphasis to thoroughly improve the program.

Following discovery of the reactor vessel head wastage at Davis-Besse, headquarters and regional staffs considered whether to send an IIT, an AIT, or an SIT to the site. According to interviews with staff and managers, the LLTF learned that the decision was strongly influenced by risk assessment. In order to develop a risk estimate, an initiating event frequency of 0.1 was assumed, which resulted in a CDF of 1E-5, which was right between the AIT and IIT criteria (per Barrett interview). This initiating event frequency of 0.1 was chosen as a compromised between 1 (which would have applied had there been a LOCA) and 0.01, which was the assumed initiating event frequency for failure of a CRDM tube due to circumferential cracking

The LLTF found that there did not appear to be a solid technical basis for choosing this event frequency, nor did there appear to be explicit treatment of pressure boundary degradation in PRAs. These shortcomings question the validity of the agency's use of risk information in making regulatory decisions.

3.3.3.2 Recommendations

3.3.3.2.1 Recommendations for NRC

- Assess if additional guidance is needed to pursue issues and problems identified during plant status reviews and if other improvement to plant status guidance is needed. Of particular important is management's engagement/ recognition of issues and the guidance that is given to the inspection staff

- Review ROP assessment process to determine if changes are needed to identify plants that may have similar problems as Davis-Besse, however, the Inspections results has only Green findings and Green PIs

- Determine if other plants, which were only assessed by PPRs for a similar length of time as Davis-Besse, have problems that need to be addressed

- Improvement to the Barrier PIs should be considered

- Management Directive 8.3 should be reviewed for possible over-reliance on risk determination that have too much uncertainty

3.3.3.2.2 Recommendations for Industry

None

3.3.4 The NRC Failed to Adequately Communicate Critical Information Regarding the Safety Performance of the Davis-Besse Nuclear Power Station

3.3.4.1 Detailed Discussion

During interviews with NRC staff and managers, the team determined that generally all had a perception from the early 1990s to 2001 that Davis-Besse was a good performing plant. Some operational problems were known and documented in inspection reports, but given that some other plants in Region III had significant operational problems which required additional oversight, the perception of good performance at Davis-Besse provided a basis for not focusing as much NRC attention on identifying or assessing its performance deficiencies. Operational performance was recognized to be declining in the late 1990s and several inspection reports document deficient licensee performance. These performance problems included significant hardware problems and human performance problems. However, given the resource constraints imposed because of other plants needing additional NRC oversight, the declining performance history of the station was not fully assessed and acted upon. Some institutional concerns with NRC Region III and NRR were identified that helped prevent adequate communication of critical Davis-Besse safety performance information.

The team interviewed several NRC Region III managers and staff and observed conduct of routine daily meetings. The team concluded that improvements in the conduct of daily plant status and issues meetings could be made to help ensure that licensee performance was adequately discussed and that senior managers were more thoroughly aware of plant performance issues. The team concluded that debriefings of inspection findings at the conclusion of region-based inspections to senior managers could be improved so that findings were adequately understood by senior management. Additionally, the inspection findings of the resident inspector staff could be better communicated to regional managers so that cross-discipline insights could be shared which could improve the assessment process and planning for future inspections.

The team concluded that the transition to the Reactor Oversight Process (ROP) was a significant burden on the inspection staff. Implementation of the ROP was a drastic change in the way the NRC performed inspections, assessed findings, and documented results. Given the number of plants in Region III that required additional oversight because of performance problems, and the significant paradigm change of the ROP, implementation of the ROP was extremely challenging.

From interviews with Region III staff and first-line supervision, RCS leakage symptoms were well known and this is also reflected in documented inspection reports. Senior managers, however, were much less knowledgeable about RCS leakage issues. NRC inspectors had reviewed and documented RCS leakage issues or their symptoms, but other than the exception of the escalated enforcement action involving pressurizer spray valve RC-2, NRC senior management had not on engaged the licensee effectively to ensure that root causes were identified and corrected. Inspectors informed the team that they believed the ROP inspection documentation threshold was too high and did not allow low-level performance observations, important for compiling an accurate assessment of licensee performance, to be documented in inspection reports. Informal mechanisms for communicating inspection observations to NRC management or to licensees at inspection debriefings was perceived to be ineffective. Internal communications to senior managers regarding performance were haphazard and external debriefings with licensee managers were perceived as ineffective if no enforcement consequence resulted. The significance determination process was also perceived to be cumbersome and a hindrance to communication of plant performance issues. This was because, unless an item directly affected operability of a structure, system, or component, and the finding fit in to an SDP worksheet, the issue was likely to be lost as being considered below the documentation threshold. Additionally, there was a perception among several inspectors that the ROP inspection program specifically precluded inspecting certain areas of plant performance. Or, due to the need to completed the minimum baseline inspection requirements, time was not available to complete inspections in areas of interest which could provide important performance insights.

As discussed in Section 3.3.1, the NRC project manager during 1999 was aware of symptoms of RCS leakage and licensee efforts to determine the source. NRR management did not recall the symptoms of RCS leakage discussed during morning status calls. The perception of the licensee's performance and of the safety posture at the Davis Besse facility was generally favorable among NRR staff and management. Thus, the information indicating a degraded condition at Davis Besse was available to NRR, but it was not widely disseminated and NRR staff presumed that the regional staff were following licensee efforts to address the problem and did not question the situation.

The Project Manager Handbook discusses the need to maintain communications between the NRR project manager and the resident inspectors on site. The guidance also directs project managers to provide highlights of significant information or events to management. However, there is no specific guidance in the Handbook regarding participation in the morning status calls nor the transfer of routine plant status information from those calls. Project Manager participation in the morning calls is a management expectation in the NRR Division of Licensing Project Management (they are specifically mentioned in the FY 2002 Operating Plan planning template for project management), but participation appears to be emphasized to varying degrees among the project managers. Also, the team was aware that not all regional offices hold morning status calls with NRR participation

3.3.4.2 Recommendations

3.3.4.2.1 Recommendations for NRC

NRR and the regional offices should establish a standardized protocol for PM participation in morning calls and NRR management should periodically participate. Project managers should be given clear expectations on their role and need to understand day-to-day plant operational information. Project managers should be encouraged to maintain a questioning attitude when considering plant operational information, especially of long standing or repetitive indications of degraded equipment or organizational performance. Regional offices should establish a standardized protocol for briefing management on region-based and resident inspector staff inspections. The present assessment process of mid-cycle and end-of-cycle meetings should be enhanced to ensure that low-threshold inspection observations are communicated and understood by management.

NEED 3.3.4.2.2

3.3.5 The NRC Failed to Provide Adequate Resources to the Oversight of the Davis-Besse Nuclear Power Station

3.3.5.1 Detailed Discussion

The inspection and oversight resources provided to Davis-Besse were minimal during much of the time period that RCS leakage in a containment, its symptoms and identification of boric acid on the reactor head were taking place. As discussed previously, there were many indications which suggested that inspections and NRC interaction with Davis-Besse should have been increased. Prior to the ROP implementation, the inspection and assessment process allowed for increased attention, however, under the ROP the program did not have this flexibility, given the inspection and PI results that were available for Davis-Besse. As discussed here, the term resources does not apply only to numbers of individuals but also to the experience and training given to these individuals.

Regional staffing for positions associated with Davis-Besse had several lapses in the late 1990s where the normal staffing compliment was not maintained For this time period, the regional staffing plan for DRP branch that oversaw Davis-Besse was a branch chief, a senior project engineer, a Senior resident Inspector and a RI. The branch chief for Davis-Besse was assigned to the branch in October 1997 and remained in that position until May 2001. This provided continuity within the regional office for the oversight of Davis-Besse The senior project engineer slot was vacant from June 1997 until June 1998 (except for a one month period) and from September 1999 until May 2000. During the initial senior project engineer vacancy the branch chief was also responsible Clinton This required a significant amount of the branch chief's time because Clinton had been shutdown since _____ and its oversight was under the IMC 0350, Oversight of Operating Reactor Facilities in an Extended Shutdown as a Result of Significant Performance Problems, process. Also during the two senior project engineer vacancy periods, Davis-Besse conducted the 1998 and 2000 refueling outages.

For the approximate one-year period of November 1998 to October 1999, there was only one resident inspector at Davis-Besse. This resulted from the senior resident inspector transferring to another site and the selection process for the new senior resident Inspector having some delays. Initially RIII planned to assign an individual to the Davis-Besse senior resident inspector position, however, when this did not materialize, the senior resident inspector position was opened to the competitive selection process. The Davis-Besse resident inspector was selected for the senior resident inspector position which then required the resident inspector position to be filled. During this period, some Inspectors from the region and other sites assisted the single resident Inspector. Also during this period the resident inspector was involved with RC-2 including. This effect included being the single inspector for the special inspection of RC-2 event and assisting the region in escalated enforcement related activities for RC-2. Assigning another inspector to preform the special inspection of RC-2 would have not only allowed the resident to spend more time on other plant issues but would have also allowed another NRC inspector to assess Davis-Besse's corrective action for RC-2.

The annual number of RIII inspection hours for Davis-Besse was below the RIII average for single unit sites for eight of nine years during the period from 1993 to 2001. Of particular noteworthiness is year 1999 in which Davis-Besse had 1422 hours compared to the region's single site annual average of 2558 hours. This coincides with the approximate one year period when there was only one resident at Davis-Besse. Also there was not a PE assigned to Davis-Besse for the last 3 months of 1999. Based on the SALP scores and the PPR assessment results it is not unexpected that Davis-Besse received fewer hours that other RIII single unit sites. During 1999 when the site only received 1422 inspection hours, CAC and rad monitor clogging Increased dramatically and the midcycle outage occurred. The regions ability to follow up on the problems that were occurring at this time was limited by inspection resources applied to Davis-Besse.

There was a high turnover rate for NRR project managers with responsibility for Davis-Besse. From 1989 to 2002, nine project managers were assigned to Davis-Besse. Interviews with several of the project managers currently employed by the NRC, indicated that project managers trips to sites occur infrequently or not at all. The Project manager handbook, Section 2.4.2, Interactions with the Regional Office, contains guidance on interactions with the resident inspector, including recommended frequent of trips to the site Clearly the guidance which suggested quarterly site visits was not met, but more importantly is the view in the handbook that the project manager and resident inspectors for an operating reactor share the responsibility for assessing safe operation of their assigned nuclear power plant, therefore, the project manager and resident inspectors must develop and maintain a strong and effective working relationship. Given the large turnover rate for project managers and their infrequent site visits, the team questioned if this expectation was satisfied.

Site visits to Davis-Besse by RIII senior management in the last half of the 1990s were somewhat limited. Travel and site dosimetry records indicate that no senior managers visited the site in 1998. Also, for the period from July 1999 to February 2002, no DRP senior managers visited Davis-Besse. This did not follows the guidance in IMC 0102, Oversight and Objectivity of Inspectors and Examiners at Reactor Facilities. Paragraph 04.05 (b) of IMC 0102 states that DRP division directors or deputy should make every effort to visit each site at least once every two years. The earlier revision to IMC 0102, which was in effect for the time period being discussed, stated that DRP division director or deputy visits should occur each SALP cycle, which for Davis-Besse had been 24 months. In should noted that during this period the regional administrator and the DRS deputy division director each visited Davis-Besse twice.

For the time period that RCS leakage in a containment, its symptoms and identification of boric acid on the reactor head were taking place at Davis-Besse, RIII had several plants in extended shutdowns and/or where starting up under the IMC 0350 process. ***LIST PLANTS AND DATE FOR THESE PLANTS*** In response to this RIII management distributed available resources to plants with the perceived needs. Since Davis-Besse was viewed as a good performer, the application of minimal resources to Davis-Besse was a conscious decision. The team acknowledged that the prioritization of inspection needs verse inspection resources has occurred in all regions to some degree. However, the structure of the ROP allows less shifting of resources since the baseline inspection program is more prescriptive than the old "core" program when specifying the minimal amount of in inspection activities that must be accomplished at each.
A point of consider in the number of opening in the region's inspection staff is the historical high turnover rate and more difficult recruiting in comparison to the other regions. A outcome of this is the higher than desired frequency of placing individual in resident inspector position before they become qualified inspectors. Neither the current resident inspector nor the former senior resident inspector (who was the resident inspector when first assigned to Davis-Besse) were fully qualified when they went to Davis-Besse. Not being a qualified inspector when assigned to a resident inspector position distractions from the site's overall inspection effort in that the non-qualified inspector could only inspect limited areas (only areas they may be interimly certified) and the senior resident inspector must spend time training the resident inspector.

Senior manager in RIII acknowledged that resident inspector have been placed at sites prior to become a qualified inspector, however, this choice was made in lieu of the alternate of having longer periods of resident inspector vacancies at sites.

Experience is important factor that directly affects an inspector's ability to identify significant issues or those having potential safety significance. This comes into play when inspectors are screening issues that licensees enters into their corrective action program. The assignment to Davis-Besse was the first commercial nuclear power plant experience for both the resident inspector and the former senior resident inspector. Providing training to inspectors is an effective means to supplemental areas where the inspector's experience is limited All of the inspectors who were questioned in interviews regarding boric acid corrosion stated they had not received training in this area. IMC 1245,______, provided the programmatic requirements for the training and certification of NRC inspectors involved with reactor oversight. Neither the version of IMC 1245 that was previously in effect not the revised (date_______) IMC 1245 provided any training on boric acid corrosion.

NEED DISCUSSION ON LIMITED MATERIALS EXPERTISES

3.3.5.2 Recommendations

3.3.5.2.1 Recommendations for NRC

Enhancements to the NRC inspector training should include: 1) provide training on boric acid corrosion; 2) increasing knowledge level on selected industry operational experience; 3) utilized Davis-Besse reactor head degradation as a case study for inspector initial certification and requalification; and 4) update training at TTC to include event lessons learned.

- Assess the need for changes to the ROP to allow regional followup on issues of potential safety signficance
- Re-enforce expectation of IMC 0102
- Conduct an assessment of staff needs in the materials area
- Establish measurements for resident staffing - use guidance
- Consider 0350 impact on regional branch assignment of facilities
- Assessment of maximum turnover rate for NRR project managers (i.e. assignment/reassignment) and update the Project Manager Handbook to be consistent with current management expectation regarding project manager site visits and interaction with regional staff
- . Reassess policy for selecting uncertified staff for resident positions

3.3.5.2.2 Recommendations for Industry

- None

3.3.6 (c) The Licensee Failed to Effectively Communicate Information to the NRC

3.3.6.1 Detailed Discussion

The task group found a number of areas where the licensee failed to convey complete or accurate information to the NRC regarding the extent of boric acid accumulation resulting from reactor coolant system leakage at Davis Besse. The following are examples that the task group found of failed communication by the licensee:

- FENOC responses to Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," and associated FENOC responses to NRC requests for information.
- FENOC description of the vessel head conditions in condition report (CR) 00-1037
- The FENOC submittal that requested license amendment 234 related to the containment air radiation monitors
- presentations prepared by FENOC that included discussions of RCS leak symptoms

FENOC responses to Bulletin 2001-01

Response to NRC Bulletin 2001-01 in FENOC letter serial No. 2731 to the NRC dated September 4, 2001, may contain inaccurate statements:

- FENOC states on page 2 that "A gap exists between the RPV head and the insulation, the minimum gap being at the dome center of the RPV head where it is approximately 2 inches, and does not impede a qualified visual inspection."

  Comment: This statement implies that the entire head can receive a qualified visual inspection. Video taping (inspection) of the reactor dome (top area) was not done.

- FENOC states on page 2 that "Inspections of the RPV head are performed with the RPV head insulation installed in accordance with DBNPS procedure NG-EN-00324, "Boric Acid Corrosion Control Program," which was developed in response to Generic Letter 88-05."

  Comment: Inspections of the RPV head were not done in accordance with NG-EN-00324 in that paragraph 6.3.1 of 00324 required. a) "The total amount of boron deposits and the amount of boron on each component should be estimated." b) "The area of the identified boron build-up should be inspected to verify that the boron is localized to the identified area. This should include a verification that a boron build-up is not located at an elevation above or below the identified areas or on other near-by components. All components with a boron build-up should be identified. The area should also be inspected to determine if boric acid could have entered the internals of a component or the inside of insulation and spread internally to a location that is not visible and is susceptible to boric acid corrosion." c) "The affected areas should be inspected to identify any signs of corrosion. This will most likely be exhibited by read b5

rust or re/brown stained boron. If corrosion is present, the amount of corrosion should be estimated. This should include an estimate of corrosion products present as well as an estimate of base metal removed." d) "The affected components should be carefully inspected to determine if a boric acid solution is present or just crystals and residue. If active leakage is present a leak rate should be measured or estimated and then action taken to stop the leakage." and h) "Identify insulation or any other type of interference which must be removed to gain access to the leak." Paragraph 6.3.5 of 00324 required that "Plant Engineering shall determine whether follow-up or more detailed inspections of the leak are necessary to fully assess component damage and determine possible corrective action. If a detailed inspection is deemed necessary, then paragraph 6.3.5 a2 required: "A detailed description of visible damage to the affected area This description should include the presence of pitting or material wastage. If corrosion is present, then the depth of pitting or wastage should be identified. This information is required for the analysis of component integrity."

- FENOC states on page 3 that "Some boric acid crystals had accumulated on the RPV head insulation beneath the leaking flanges. These deposits were cleaned (vacuumed). After cleaning, the area above the insulation was videotaped for future reference.

  Comment: By interview with the RCS system engineer on 7/3/02, a statement was made indicating that the reactor head insulation area cleaning was planned but never performed, consequently, a video taping of the cleaned insulation head area was also never made.

- FENOC states on page 3 (April 2000 Inspection Results) that "Inspection of the RPV head/nozzles area indicated some accumulation of boric acid deposits. The boric acid deposits were located beneath the leaking flanges with clear evidence of downward flow. No visible evidence of nozzle leakage was detected."

  Comment: Review of the 4/17/00 video taping of the RPV head included verbal comments describing the boric acid accumulation as "mountains and mountains," not "some" as denoted in the FENOC letter to the NRC.

- FENOC states on page 3 (April 2000 Inspection Results) that "The boric acid deposits were located beneath the leaking flanges with clear evidence of downward flow. No visible evidence of nozzle leakage was detected."

  Comment: FENOC states on page 2 (April 1998 Inspection Results) that "There were lumps of boron, with the color varying from brown to white." The brown color would indicate ferritic corrosion of the RPV head adjacent to the nozzles. By interview with the RCS system engineer on 7/3/02, a statement was made indicating that brown boric acid was evident on top of the insulation area, and below the insulation area, also indicating ferritic corrosion of the RPV head. Materials above the CRDM flanges would produce the brown boric acid build-up. In addition, the licensee never removed the boric acid build-up around the upper dome nozzles to determine the leakage source and pathway as required by NG-EN-00324, consequently, the statement that "No visible evidence of nozzle leakage was detected " is without basis.

- FENOC states on page 3 (Subsequent Review of 1998 and 2000 Inspection Videotapes Results) that "Since May 2001, a review of the 1998 and 2000 inspection videotapes of the RPV head has been performed. This review was conducted to re-confirm the indications of boron leakage experienced at the DBNPS were not similar to the indications seen at ONS and ANO-1; i.e., was not indicative of RPV nozzle leakage. This review determined that indications such as those that would result from RPV head penetration leakage were not evident."

  Comment: Attempts were made to obtain any related report on the tape reviews, and how it was determined that RPV head penetration leakage was not evident given that a bare metal head (or nozzle) inspection was never performed. The origin of the brown boric acid was never explained. Consequently, the statement that "This review determined that indications such as those that would result from RPV head penetration leakage were not evident" is without basis.

- FENOC states on page 12 that "The DBNPS performs visual inspections for evidence of leakage by examining the RPV head surface and the CRDM flanges per the requirements of NRC Generic Letter 88-05,..... If pressure boundary leakage is suspected, supplemental examinations of the affected CRDM nozzle will be performed to characterize the integrity of the nozzle."

  Comments: PCAQR 96-55 (Boric Acid on RX Vessel Head) initiated on 4/21/96 indicated that "There could also be corrosion damage within the reactor vessel head penetration due to boric acid corrosion resulting from a through wall crack in the CRDM nozzle." The PCAQR also states that procedure NG-EN-00324 (Boric Acid Corrosion Control) "... may not have been followed to identify the scope of problem." The boric acid build-up around the CRDM/RPV upper head areas was not removed and inspected until after the February 2002 event during 13RFO.

The supplemental response to NRC Bulletin 2001-01 (FENOC letter (Serial No. 2735) to the NRC dated October 17, 2001) may contain inaccurate statements.

FENOC states in the letter, "This submittal provides updated and additional information support of the basis for the continued safe operation of the Davis-Besse Nuclear Power Station (DBNPS) until its next scheduled refueling outage commencing in March 2002, at which time the Control Rod Drive Mechanism (CRDM) nozzles and Reactor Pressure Vessel (RPV) head penetrations will undergo qualified visual inspections or appropriate supplemental inspections."

- Page 2 of the letter indicated that "This RV Head Nozzle and Weld Safety Assessment demonstrates the postulated crack will take approximately 7.5 years to manifest into an ASME Code allowable crack size. Applying the 7.5 years to the May 1996 inspection projects the worst-case allowable crack size being reached in November 2003. It is important to note the allowable crack size will still maintain an ASME Code safety factor of three. A Finite Element Gap Analysis was performed by Structural Integrity Associates to verify the gaps between the CRDM nozzles and the RPV head during normal operation would permit through-wall leakage from any nozzle or through-weld cracks in the J-groove weld to be observed via boric acid crystal deposits. This analysis concluded that all but four nozzle/penetration interfaces would show visible leakage.

These four nozzles are in the least stressed area of the RPV head, and where no leakage attributed to circumferential cracks has been observed at any other plants."

Comment: The statement issued to the NRC indicates that through-wall leakage would be observed via boric acid crystal deposits (which implies that the leakage would be detected and corrected). The leakage was detected (very large amounts of boric acid build-up having a brown color beginning in 1996 through 2000 outages), but never corrected. The statement in the NRC Bulletin submittal implies that any RDM leakage would be discovered and corrected. The four nozzles mentioned on page 2 of the letter, where leakage wasn't expected, are later identified on page 4 of Attachment 1 to the letter as nozzle numbers 1, 2, 3, and 4. In conflict with the analyses performed, nozzle 3 penetration was discovered to have to greater leakage and subsequent corrosion damage to the RPV head.

- FENOC states on page 3 of Attachment 1 to the NRC letter that "In summary, results from previous inspections of the CRDM nozzle penetrations provide reasonable assurance for the continued safe operation of the DBNPS until the next refueling outage in March 2002."

  Comment: The CRDM and surrounding area of the RPV head could not be visually inspected due to the large amounts of boric acid build-up There is no basis for the statement "... previous inspections of the CRDM nozzle penetrations provide reasonable assurance for continued safe operation of the DBNPS until the next refueling outage in March 2002."

Responses to NRC Requests for Additional Information Concerning NRC Bulletin 2001-01 in FENOC letter Serial No. 2741 to the NRC dated October 30, 2001, may contain inaccurate statements.

This letter provides responses to the NRC staff's requests for additional information concerning the DBNPS Bulletin response letter dated 9/4/01.

- Page 1 of Attachment 1 to the letter states that "The inspections performed during the 10^{th}, 11^{th}, and 12^{th} refueling outages "... consisted of whole head visual inspection of the RPV head in accordance with the DBNPS Boric Acid Corrosion Control Program pursuant to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR plants."

  Comment: As stated in Davis-Besse CR 96-55, the inspection was neither "whole head" (page 9 indicates that 50 to 60% of the head area was inspected) nor in accordance with procedure NG-EN-00324, Boric Acid Corrosion Control Program (see page 1 and 1a of CR).

- FENOC states on page 1 of Attachment 1 that "Following 12RFO, the RPV head was cleaned with demineralized water to the extent possible to provide a clean head for evaluating future inspection results.

Comment: By interview with the RCS system engineer on 7/3/02, it was indicated that the first few rows (which included nozzle 3) were not cleaned following 12RFO because of the nature of the boric acid build-up and ALARA considerations. With the CRDMs and surrounding areas not cleaned, there would be no baseline for future inspection evaluations. The statement included in the NRC letter would only be true for those areas of the RPV head that were thoroughly cleaned and inspected.

- FENOC states on page 1 of Attachment 1 that "During the 12RFO Inspection, 24 of the 69 nozzles were obscured by boric acid crystal deposits that were clearly attributable to leaking motor tube flanges from the center CRDMs. A further subsequent review of the video tapes has been conducted and corroborates the previous statements and conclusions stated in letter Serial Number 2731 and Serial Number 2735 that the results of this review did not identify any boric acid crystal deposits that would have been attributed to leakage from the CRDM nozzle penetrations, but were indicative of CRDM flange leakage."

  Comment: The licensee appears very positive in their assessment of boric acid build-up on the RPV head in their use of the words "clearly attributable to leaking motor tube flanges from the center CRDMs." This assessment does not address the brown boric acid noted in 1996, and by the RCS system engineer for subsequent outages. The licensee also refers to yet another video tape review performed subsequent to the reviews made reference to Ser. Nos. 2731 and 2735. (An information request has been submitted to the licensee). Once again, since the boric acid build-up on the RPV upper dome was not removed, the statement "... this review did not identify any boric acid crystal deposits that would have been attributed to leakage from the CRDM nozzle penetrations ..." has no basis.

Response to Bulletin 2001-01 In FENOC letter Serial No 2744 to the NRC dated October 30, 2001, may contain inaccurate statements.

During a public meeting between DBNPS staff and the NRC staff on October 24, 2001, concerning FENOC response to NRC Bulletin 2001-01, the DBNPS staff committed to provide pictorial documentation of the visual examinations of the RPV head performed during the 10th, 11th and 12th RFOs. **This document provides the response, and was requested to be withheld from public disclosure pursuant to 10CFR2.790**

CHECK PORTIONS OF THE FOLLOWING FOR PROPRIETARY INFORMATION

- RPV Head 11RFO Inspection Results shows photographs of nozzle penetrations that were inspected via video. This document indicates that the pictures were clipped form video taken the Spring of 1998, and indicates that "... a good video inspection was able to be performed for those 50 drives that were not obscured by boron from leaking CRDM flanges. Although much more video can be viewed, these attached pictures are representative of the condition of the drives and the heads. We attempted to capture in still photographs all of the outer most drives since they are the most susceptible to circumferential cracking based upon finite element analysis..."

  Comment: The pictures shown in the submittal to the NRC included approximately 3 of 4 quadrants of the RPV head. The quadrant not shown included those areas where boric acid build-up was present. The statement that "... these attached pictures are representative of the condition of the drives and the heads." is inaccurate, since those CRDM penetrations that had boric acid build-up are not shown. The submittal also indicated that "We attempted to capture in still photographs all of the outer most drives ..." was inaccurate, in that drives that were downhill from nozzle 3 were not included

- RPV Head 12RFO Inspection Results shows photographs of nozzle penetrations that were inspected via video. These photos were taken from their 2000 Spring outage videotapes. The document states that "These drives were video taped because they had boron deposits in the vicinity of the CRDMs Completely clean drive penetrations are not depicted here."

Comment: Contrary to the above statement, the pictures depicted in the NRC submittal include 10 CRDMs located on the "clean side" of the RPV head which includes less than one quadrant of the RPV head. The licensee's statement that "Completely clean drive penetrations are not depicted here." implies that other than the 10 CRDMs shown in their submittal to the NRC, all penetrations are clean. This statement is inaccurate. By interview with the RCS system engineer, the first few rows of CRDMs (from the upper dome area) were never cleaned following 12 RFO in 2000.Licensee/NRC Staff Action or Response:

Condition Report (CR) 00-1037

The response to CR-00-1037 indicated that all the boric acid accumulation on the reactor head had been removed during the cleaning process. If the NRC inspectors had followed up on this CR, they most likely would have concluded that the licensee's actions were appropriate based on its descriptions of the licensee's actions and of the vessel head condition.

The response to CR-00-1037, detailing accumulation of boron on reactor head, provided the perspective that all boron had been removed from the head. The CR description indicated that boron had accumulated in the area of the head control rod drive (CRD) nozzle penetrations and on top of the thermal insulation under the CRD flanges. It also mentioned CR-00-0782, which initially identified boron deposits coming from the weep holes and having a red/brown color. The boron accumulation was worst on the east with a thickness of approximately 1.5 inches on the side of the head and pooled on the flange in the area of the studs. The estimated quantity was 15 gallons. Pictures attached to CR-00-0782 clearly depicted the condition of the boron accumulation. This condition was identified on April 6, 2000.

The response to CR-00-1037 mentioned NRC generic letter 97-01 with the following wording:

> "... The letter requires licensee to maintain a program for ensuring a timely inspection of the control rod drive mechanism (CRDM) and the vessel closure head penetrations. The program is required due to the degradation of the CRDM nozzles caused by Primary Water Stress Corrosion Cracking process. In order to perform required inspections the nozzles as well as the penetrations must be free of boron deposits Once the head is free from the boron, new boric acid deposits may be easily noted and remedial action taken."

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The Remedial Actions section of the CR response stated, "Accumulated boron deposited between the reactor head and the thermal insulation was removed during the cleaning process performed under WO 00-001846-00. No boric acid induced damage to the head surface was noted during the subsequent inspection." In the description of work for WO 00-001846 the statement, "Work performed without deviation", was annotated

Based on interviews, the task group understood that all boric acid deposits were not removed from the head during the cleaning efforts in 12RFO. Also, a post-cleaning video inspection tape shows the remaining boric acid deposits.

The former NRC senior resident inspector mentioned in his interviews that he had reviewed a CR during 12RFO that described the boric acid deposits on the head *(he was unsure which specific CR that he reviewed).* The SRI stated that he did not provide any follow-up Inspection effort to this CR or the condition of BA deposits on the reactor head The task group determined this condition could have been Inspected/ followed up under the baseline inspection program which had been initiated at the approximate time (April 1, 2000). Specifically, several CRs were written regarding BA on the reactor head and the guidance in Plant Status, Appendix D of IMC 2515 directs the resident to review the licensee's deficiency of non-conformance reports to become aware of safety significant problems that can be followed up through the baseline program. Based on graphic description and attached photographs to CR-00-0782 the team concluded that some inspector follow-up was warranted It should be noted that the issues/ CRs which inspectors pursue are discretionary and are based several factors, i.e., risk significance, other issues being reviewed (workload), etc

The response to CR-00-1037 was worded such that a reader would believe that all boric acid deposits had been removed from the head during the cleaning process. While the team noted that this CR was not reviewed by the NRC, the task group concluded that if it had been reviewed, the inspector may have determined that the licensee's corrective actions were adequate. To determine that the head had not been fully cleaned would have required firsthand observation of the cleaning effort, review of the videotape or specific question and answers from the involved Individuals.

License Amendment No. 234

The License Amendment Request (LAR) for containment radiation monitors was submitted on July 25, 1999, and was approved on November 16, 1999, as License Amendment No. 234. The containment radiation monitors are used as an RCS leakage detection system. The LAR proposed changing the operability requirements for the containment air radiation monitors, but did not discuss the operating challenges (i.e., frequently clogged filters) faced by the system.

The LAR contained no information to imply that there was a material condition problem with the containment air rad monitors. The LAR was part of a larger request to move some technical specifications (TS) systems to the technical requirements manual (TRM) and for the RCS leakage detection TS to reflect the Babcock &Wilcox Improved Technical Specifications (ITS) [NUREG XXXXX]. The LAR was a straightforward request to implement NRC guidance for removal of systems from the TS to the TRM or implementation of line-item TS improvements to match the B&W ITS. Minimal NRR technical review was required.

Although not stated in the LAR, this submittal was made during a period when frequent filter changeouts were required. Iron oxide found during this period and HEPA filters installed in containment.

The amendment resulted in only requiring one rad monitor (gas or particulate) operable instead of previously requiring both operable. Note: there are 2 sets (trains/skids) of containment air radiation monitors, each set has gas, particulate, and iodine (iodine not mentioned in SAR or TS). Each train shares a common containment air flowpath. Removing one train from service removes all 3 monitors from service.

The change resulted in essentially 1 of 4 monitors required operable and eliminated the 6-hour shutdown action statement (not TS Section 3.0.3) that existed previously.

The change had the indirect benefit of eliminating the 6 hour shutdown TS action entry if one train remained inoperable.

FENOC presentations

FENOC presentations indicated that boric acid deposits remained on the vessel head.

FENOC presentations made to the NRC on November 14, 2001, and January 23, 2002, indicated that some CRDM nozzles would be masked by boric acid deposits, thus precluding visual inspection for leakage. Slide 5 in the November 14 presentation (entitled Leakage Detection) indicated that previous "inspections provide reasonable level of assurance for nozzles without masking boron deposits." Slides 4 and 5 in the January 23 presentation specify visual inspection for unobscured nozzles and supplemental NDE inspections for obscured nozzles.

The briefing packages for Commissioner Merrifield's April 27, 2001, visit and the December 16, 1998, and March 2, 2001, Management Meetings between Region III and Davis Besse did not mention the continuing problem with RCS leakage in the containment and the resulting buildup of boric acid deposits on CACs and rad monitors. In addition Commissioner Merrifield's briefing package mentions on page 19 that, "Reactor Vessel Head Cleaned/Visually Inspected During Past Refueling Outages" and "No Cracking or Leakage Found." The statement the briefing package that the reactor head had been cleaned and visually inspected in past RFOs is inconsistent with actual cleaning efforts from past RFOs. There were some levels of licensee management who were aware of this fact, however, the inaccurate information was still provided in the briefing package.

The plant status sheet developed by Region III staff to brief the Regional Administrator for his March 21, 2001, site visit, mentioned under the "Equipment" heading that no significant equipment concerns existed. In the same paragraph there is a sentence, "CAC cleaning monthly", but no amplifying information. Based on this listing of information, it appears that Region III staff did not see the continuing problem with CAC cleaning and the RCS leakage that was causing the CAC fouling as a significant equipment issue. There was no mention of the rad monitor filter clogging or the iron oxide deposits even though this was also a continuing problem which provided insights on significance of the problems.

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At the time of the December 1998 management meeting, and for the Commissioner's visit and the March 2, 2001, management meeting, Davis Besse had experienced (and Region III seemed to be aware of) problems w/ CAC and rad monitor clogging, however, this was not an item on the agenda for either meeting. Since the region was aware of the ongoing nature of containment RCS leakage and the lack of the licensee's success in resolving the problem, Region III should have requested that this topic be discussed in a management meeting.

3.3.6.2 Recommendations:

3.3.6.2.1 Recommendations for NRC:

The NRC should take steps (processes established and resources provided) to verify information provided by licensees.

3.3.6.2.2 Recommendations for Industry:

Licensees should be strongly encouraged to provide complete and accurate information on plant operations and conditions to the NRC

3.3.7 (q) The NRC Failed to Provide or Implement Licensing Process Guidance

The task group noted that in a number of areas related to the licensing process, the NRC either did not provide adequate guidance to the NRC staff, or did not implement existing guidance. These areas were:

- regulatory commitment tracking,
- industry topical report review process,
- license amendment review process
- documentation of the decision to defer shutdown
- review of the periodic inservice inspection report
- interface between the NRC project manager and the resident inspectors
- license renewal technical basis
- containment testing requirements

The task force considered some of these deficiencies to be contributing factors to the regulatory posture that allowed the Davis-Besse situation to occur. The other deficiencies are incidental to the problem and were uncovered in the course of the review conducted by the task force.

3.3.7.1 Detailed Discussion

Regulatory Commitment Tracking

Regulatory commitments are documented actions voluntarily agreed to by licensees that, together with applicable regulatory requirements, form the licensing basis for the plant. Many of these commitments are provided in docketed correspondence such as licensee event reports and responses to generic communications. Regulatory commitments are relevant to the Davis

Besse situation because, historically, a significant number of commitments at Davis Besse were related to boric acid corrosion control, including measures taken to institute a boric acid control program in response to Generic Letter 88-05.

NRR guidance for managing licensee commitments to NRC is contained in Office Letter-900, "Managing Commitments made by Licensees to the NRC," and in the Project Manager Handbook, maintained online by the Division of Licensing Project Management. The office letter references NEI 99-04, "Guidelines for Managing NRC Commitment Changes," stating that it provides acceptable guidance for controlling regulatory commitments. The NEI guidance directs licensees to submit a periodic report to the NRC of changes to commitments. Additional NRR guidance regarding licensee commitments to NRC is in LIC-100, "Control of Licensing Bases for Operating Reactors." Table 4 in LIC-100, "Regulatory Commitments" discusses NRC Verification and Monitoring:

> The NRC Inspection program may review a regulatory commitment associated with a particular issue or technical area. In general, however, the inspection program does not assess how well licensees control regulatory commitments. NRR plans to assess the licensees' commitment management programs and their implementation of those programs. This activity will be performed under the DLPM responsibilities for "Other Licensing Tasks."

The task group noted that the NEI guide expressly deals with changes to regulatory commitments. It does not seem to be applicable to overall management of the commitment tracking process nor is it necessarily applicable to all outstanding commitments From NEI 99-04:

> "The guidance applies to commitments communicated to the NRC under the current regulatory structure. Licensees must decide how they will address commitments communicated to the NRC prior to the promulgation of the guidance document" in 1999.

The office letter directs project managers to audit the licensee's commitment management program. The Handbook does not reference the office letter, mention the audit requirement, nor does it provide guidance for review or disposition of the periodic commitment change report submitted by licensees. NRR project managers contacted by the task group were not aware of the requirement, and the most recent project managers for Davis Besse had not conducted an audit.

FENOC letter to NRC dated November 15, 2000, provided the periodic Commitment Change Summary Report to the NRC. It contained 2 items on containment air coolers Containment air coolers exhibited frequent clogging during plant operation, indicating a leak in the RCS, Commitment nos. 014438 and 007319 related to CA air flow. The Davis-Besse project managers did not recall reviewing the report.

Inspection Report 98011, Sep. 9, 1998, documented problems discovered by the licensee in the D-B commitment management program. Problems documented were; the licensee's commitment database not clearly summarizing commitments, undocumented justification for deviations from commitments, and changes made to implementation documents with sufficient basis. The inspection team concluded that the corrective action plan was sufficient to address

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the issue. There appears to be no further NRC follow up on the issue.

Industry Topical Report Review Process

NRR guidance for topical report review is given in LIC-500, "Processing Requests for Reviews of Topical Reports." Topical reports are technical reports on specific safety-related subjects submitted by industry organizations that may be reviewed independently of a specific licensing review. The objective of the topical report review process is to improve efficiency by allowing the staff to review a methodology or proposal that will be used in multiple licensing actions The guidance in LIC-500 include criteria for accepting a topical report for review. One criterion is that the report is expected to be referenced in a number of license amendments or other licensing actions. LIC-500 allows exceptions to these criteria, but justification must be supplied by the applicant. The LIC-500 guidance does explicitly not discuss a process for NRC to initiate reviews of industry reports that are not submitted. For example, the EPRI Boric Acid Guidebook provides generic guidelines to PWRs, but the guidebook was never reviewed by NRC.

LIC-100, "Control of Licensing Bases for Operating Reactors" also discusses the same criteria for staff review of topical reports. This guidance reiterates that topical reports are reviewed only in support of licensing or anticipated licensing actions.

COM-204, "Interfacing with Owners Groups, Vendors and NEI," includes guidance on certain submittals from vendors and owners groups. It discusses submittals made for information only, where a formal NRC review is not requested. In these cases, the guidance allows for a cursory NRC review to determine if the submittal conflicts with NRC rules, regulations or policies. This results of this review do not constitute NRC acceptance or agreement with the material, but allows the staff the opportunity to inform the applicant of any discrepancies found.

License Amendment Review Process

As discussed elsewhere in this report, clogging of the containment air coolers and containment air radiation monitor filters with corrosion products were indications of significant RCS leakage. The task group found 2 license amendments related to this equipment. The first was D-B License Amendment number 180 issued on September 9, 1993, allowed use of the containment gaseous radiation monitoring system as an alternative means of detecting RCS leakage. The SE, FSAR and TS bases were reviewed to determine if adequate background information was available to operators to use filter change frequency as an indicator of an RCS integrity problem. See FSAR 5.2.4.3 for details of system operations. TS bases were very scant on the system, but referenced RG 1.45.

The second was License Amendment number 234 that included a change for containment radiation monitors (RCS leakage detection systems) and was issued on November 16, 1999. The licensee's request contained no information to imply that there was a material condition problem with the containment air rad monitors. The submittal was part of a larger request to move some TS systems to the technical requirements manual and for the RCS leakage detection TS to reflect the B&W improved technical specifications. The LAR was a straightforward request to implement NRC guidance for removal of systems from the TS to the TRM or implementation of line-item TS improvements to match the B&W ITS. Minimal NRR technical review was required.

Although not stated in the LAR, this submittal was made during a period when frequent filter change outs were required. This LAR is discussed in more detail in Section 3.3.6.

The safety evaluation for the license amendment was prepared by the NRC project manager for Davis Besse and received the concurrence of managers in three technical branches (EEIB, EMCB, SPLB). The justification for the change made to the RCS leakage detection system included the capability of remaining operable systems and compensatory measures to detect RCS leakage when one o the required systems became inoperable. The Safety Evaluation also considered that the change was consistent with NUREG-1430, "Standard Technical Specifications - Babcock and Wilcox Plants." There was no discussion in the Staff's evaluation of the current state of the system or its operating environment.

The task group found that the SER conformed with the guidance in LIC-101, License Amendment Review Procedures." The Office Instruction does direct the project manager to solicit input from resident inspectors to verify information by the licensee. However, judging the ordinary nature of the information in the LAR, the staff would not have seen a need to check with the resident staff.

Documentation of the Decision to Defer Shutdown

The basis for the NRC decision to allow Davis Besse to delay shutdown past December. 2001 was not well documented. The December 4, 2001, letter from the NRC to FENOC allowed plant operation past December 2001 based on information submitted by FENOC in November 2001. However, the letter does not provide the basis for the staff decision in sufficient detail to determine what evaluation/verification was conducted by the staff.

The December 4 letter contrasts with the detailed basis provided in the proposed order to shutdown Davis Besse and DC cook (a November 11, 2001 memo to the Commission forwarded the proposed orders for information). The proposed order cited inspection results at facilities with similar susceptibility ratings as Davis Besse and large uncertainties in the cracking mechanism and extent of cracking at the plants. Staff assumed that RCPBs could be compromised at the plants, and therefore required shutdown.

The lack of sufficient background to the decision in the December 4, 2001, could lead the public to question the motivation for the staff's decision and the usefulness of risk-informed regulation. Risk informed regulation of NPPs includes decisions on allocation of inspections, assessment of the significance of occurrences (SDP), and assessment of the severity of violations (SDP).

Based on several interviews of NRC staff conducted by the task group, it appears that risk models do not appropriately account for degradation of passive components. Some staff expressed the opinion that the NRC has become risk-based as opposed to risk-informed, that issues cannot be pursued without having a risk number attached to them, and that deterministic safety requirements have been discounted.

Review of the Periodic Inservice Inspection Report

ISI Summary report for D-B dated August 22, 2000, provided the results of the ISI activities related to the 12th cycle and 12RFO. P. 20 of the report lists CDR nozzle to closure head weld visual inspection results for CRD This indicates that only peripheral CRDM nozzles were inspected

Licensee submit ISI summary reports to the NRC as required by ASME code, however, NRC rarely reviews the information D-B submitted an ISI summary report (see OBF-13) that was not reviewed by NRC staff.

DE, Ted Sullivan, explained in an email response that NRC rarely reviews the reports:
"Ken answered your question with respect to the steam generator inspection summary reports, which are required by TS rather than by ASME Code requirements. The ASME Code, Section XI requires that ISI summary reports be submitted to the regulatory agency (NRC). The agency does receive these reports. EMCB does not do any formal review of these reports. Occasionally they are glanced at but this is rare. Many years ago in the course of contractor reviews of the ISI relief requests, the contractor would look at these reports to see if they could find any code reliefs that were buried in the ISI reports. Occasionally one was found and pointed out to the licensee that this was not an appropriate vehicle for code relief and that a relief request was needed. The contractors no longer perform this type of review and haven't for some time.

We at NRR do not see a value in having these reports sent to headquarters. With respect to whether or not the regions look at these reports, you would have to contact some of the inspectors or section chiefs there. I doubt that they look at them but I am not certain."

Interface Between the NRC Project Manager and the Resident Inspectors

Project Manager Handbook section 2.4, guidance on interactions with licensee includes specific guidance on responses to licensees concerning generic communications, interactions with resident inspectors, and visits to the site.
PM Handbook Section 2.4.1, interactions with the Licensee designates the PM with the responsibility of providing responses to Gcs. It also discusses GC follow up by PM.

> "there are some cases where the staff intentionally does not perform a detailed review in response to certain Bulletins, Generic Letters, etc. For these issues, the staff must ensure that the requested actions are adequately addressed by the licensee. The PM subsequently sends the licensee an acknowledgment letter, with a caveat stating that the licensee's response may be subject to future inspection or auditing. In these cases, a large part of the staff's basis for the acknowledgment closeout letter is the future inspection of all plants (or a sample of plants).

The Project manager handbook, Section 2.4.2, Interactions with the Regional Office, contains guidance on interactions with the resident inspector, including recommended frequent trips to the site.

> "The PM and the resident inspector (RI) for an operating reactor share the responsibility for assessing safe operation of their assigned nuclear power plant. Therefore, the PM and RI must develop and maintain a strong and effective working relationship."

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Observation: It's difficult to establish a strong working relationship when project managers turnover at a high rate.

> Communication with the RO through the RI and the appropriate projects branch in the RO should be established and maintained. The PM should arrange to visit the RI at the site periodically to become better acquainted with the plant, its systems and special features, and its staff in association with the RI. To the maximum extent possible, these visits should also be used to perform field observations and verifications of licensing matters under review by the PM. It is important to demonstrate a unity of purpose between the PM and the RI in carrying out their respective responsibilities. Site visits should be arranged consistent with the work schedule of the PM and RI. Such visits should be made at least quarterly, and more frequently when issues warrant. However, the exact frequency and duration of these visits should be determined between the PM and his or her management.
>
> It is of paramount importance that the PM and RI thoroughly understand each others functions and remain knowledgeable of current issues in which each is involved. To achieve this understanding, the PM should use telephone calls and accompany the RI or other region-based specialists in conducting portions of inspections during the PMs site visits (see Section 5.1.7, Participation in Regional Inspections), and to become familiar with the plant.

Several interviews indicated that PM trips to sites occur infrequently or not at all.

<u>License Renewal Technical Basis</u>

License renewals rely on plant aging management programs.
Each licensee's GL 88-05 program is part of basis for license renewal. Boric acid corrosion is accounted for in nuclear power reactor license renewals.

NPP licenses are renewed under 10 CFR Part 54. Licensee aging management programs are reviewed as part of the license renewal process. The guiding document is NUREG 1801, Generic Aging Lessons Learned (GALL) Report.

GALL report Section XI.M10, Boric Acid Corrosion (p XI M-39), evaluates the adequacy of GL 88-05 as a means to address this issue in the context of plant aging management. Staff has found these programs acceptable.

In an interview, P T Kuo, chief of the license renewal branch, stated that the staff's finding of adequacy is limited to the licensee's program, but that licensee implementation of those programs is outside his area of responsibility. He also stated that his staff plans to update the GALL report to reflect the lessons learned form Davis Besse. NRR should ensure that the GALL report and license renewal review practices are updated to reflect lessons learned from the Davis Besse event.

<u>Containment Testing Requirements</u>

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NRC staff did not know if the Davis Besse containment retest should be an ILRT or a LLRT. Although several containments have been retested following SG replacements, the staff had not previously considered the issue because SG replacement s are conducted under the 50.59 process.

3.3.7.2 Recommendations

3.3.7.2.1 Recommendations for NRC

- The NRC staff and industry should review the risk-informed regulatory framework, clearly define which activities should be addressed by risk-informed methods and which should be addressed by deterministic methods, and establish means to evaluate the significance of deterministic activities.

- NRC needs to review industry guidance documents to understand what guidance is being provided to licensees and to select safety significant topics to review in detail to assess the quality of the guidance.

- Review/implement guidance on NRC management and project manager visits to sites. Implement guidance in the PM handbook for site visits and PM coordination with Resident inspectors.

- NRR needs to ensure implementation of commitment evaluation/closure. Implement LIC-900, "Commitment Management Process"

- Update guidance and provide training to project managers. Consider the usefulness of periodic report made by licensees if revised guidance will not direct staff review of the information. Determine if ISI summary reports submitted by licensees should be reviewed.

- NRC should thoroughly document the basis for accepting a deviation from guidance. Clear criteria for deviating from NRC guidance should be established Assess the use of risk methods and integration of results into decision-making related to short-notice licensing actions.

- Guidance is needed to ensure independent verification of information related to significant licensing decisions.

3.3.7.2.2 Recommendations for Industry

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3.4 (rc4) The NRC and Industry Failed to Establish Adequate Requirements and Guidance for Addressing Alloy 600 Nozzle Cracking and Boric Acid Corrosion of Carbon Steel Components

The task group found that a root cause of the condition at Davis Besse was that neither the NRC nor industry established adequate requirements and guidance for addressing Alloy 600 nozzle cracking and boric acid corrosion of carbon steel components The task group determined that:

- The NRC failed to provide adequate requirements for the inspection of RCS components for leakage and degradation from boric acid accumulation.
- The NRC failed to provide adequate guidance to NRC staff to effectively implement the reactor oversight process
- The industry failed to provide adequate requirements for detecting and correcting Alloy 600 nozzle cracking and corrosion from boric acid accumulation.
- The NRC failed to provide adequate procedures and guidance for detecting and correcting Alloy 600 nozzle cracking and corrosion from boric acid accumulation.

The task group made the following recommendations to address the deficiencies in this area:

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3.4.1 (d) The NRC Failed to Provide Adequate Requirements

3.4.1.1 Detailed Discussion

The LLTF reviewed applicable regulatory requirements, including Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, 10 CFR Part 50.55a, and Davis-Besse technical specifications. The team found that this body of requirements did not contain sufficient requirements to direct the licensee to identify and resolve coolant leakage from the reactor vessel head. Additionally, the NRC had not consistently enforced violations resulting from pressure boundary leakage, nor had the staff effectively maintained corporate knowledge of enforcement regarding vessel head corrosion in 1987. In conducting its review, the LLTF found inconsistent levels of understanding of the scope and applicability of Code requirements among staff and management responsible for nuclear power plant oversight.

ASME

Requirements are contained in 10 CFR 50.55a and plant technical specifications at section 4.0.4. Both of these reference Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code. Davis-Besse was committed to the in-service inspection requirements of the 1986 edition of the code from September 21, 1990, through September 20, 2000; since then, the licensee has been committed to the 1995 Edition through the 1996 Addenda.

Per the requirements of Table IWB-2500-1 of Section XI, and the licensee's ISI plan, the licensee is required to conduct an RCS leakage test at nominal operating pressure prior to plant startup following each reactor refueling outage. IWA 5241 requires a direct visual examination, known as a VT-2, of the accessible external exposed surfaces of pressure retaining components for evidence of leakage from non-insulated components. Regarding insulated components (at Davis-Besse, the RPV head), IWA-5242 states that VT-2 may be conducted without removing insulation by examining the accessible and exposed surface and joints of the insulation. When doing such examinations, the surrounding area shall be examined for evidence of leakage. Discoloration or residue on surfaces examined shall be given particular attention to detect evidence of boric acid accumulations from borated reactor coolant leakage. Corrective measures are specified in article IWA-5250, which requires leakage sources of boric acid residues, and areas of general corrosion, to be located. IWA-5250(b) also requires that components with areas of general corrosion that reduce the wall thickness by more than 10% shall be evaluated to determine whether the component may be acceptable for continued service, or whether repair or replacement is required.

The code does not require volumetric NDE of vessel head nozzles as a means to identify and characterize cracks in those nozzles.

In September 2001 (roughly concurrent with the review of licensee responses to Bulletin 2001-01), NRC staff members who serve on ASME code committees wrote to ASME and proposed that the inspection requirements be changed to VT-2 examination of 100% of the reactor vessel head surface or under the head NDE capable of detecting and sizing cracking.

The Code requirements for mechanical joints (e.g., CRDM flanges at Davis-Besse) in the RCS differ from those for welded joints. Provided that the licensee performs an assessment of any leakage from mechanical joints, and the leakage volume is within technical specification limits, it is permissible for plants to start up from refueling outages with known leakage from mechanical joints. The LLTF found that the licensee's practice of operating with known CRDM flange leaks helped to mask the VHP leakage.

As discussed in other sections of this report, there have been several cases of through-wall cracking of CRDM nozzles. In fact, the licensee for Arkansas Nuclear One has informed the Commission that a through wall crack on a CRDM is a statistical certainty. In the case of Davis-Besse, the LLTF determined that the lack of a requirement in the ASME code to remove the vessel head insulation during system pressure tests contributed to the missed opportunities for early identification of nozzle leakage and resulting corrosion of the vessel head. Also, the failure to conduct periodic volumetric NDE on the nozzles prevented the licensee from detecting cracks before they progressed to the point of leakage.

Plant technical specifications typically prohibit operation with known pressure boundary leakage. Therefore, relying on boric acid residues to show that through wall nozzle leakage has occurred is a lagging indicator. In cases where pressure boundary leakage has occurred, the NRC's responses have been inconsistent over the years. Based on staff interviews and document reviews, the LLTF found a range of agency responses, from no action taken in the case of Arkansas Nuclear One, to the granting of enforcement discretion in the cases of VC Summer and Oconee, to taking enforcement action against Palisades. Several factors contributed to this phenomenon, including internal communications, the introduction of the ROP, and changes in the enforcement policy. As of the preparation of this report, the NRC's

Office of Enforcement was working with NRR to develop a uniform policy for dealing with pressure boundary leakage.

Exacerbating the issue is the treatment of pressure boundary integrity within the framework of risk-informed regulation. The LLTF found that the performance and degradation of passive components has not been explicitly accounted for in PRAs, and may even be outside the technical scope of PRAs. This factor has led to difficulty among regional, NRR, and OE staffs in characterizing the significance of, and responding accordingly to, instances of pressure boundary leakage.

Foreign Requirements/(EPRI BAC Guide Book?)

NRR accepted inadequate inspection requirements (ASME -Visual insp.) of Reactor Vessel heads knowing the foreign experience and the existence of the Oconee circumferential cracking_

NRC Bulletins 2001-01 and 2002-02 continue to rely on the susceptibility model for gaging the level of inspection. The vessel head penetration susceptibility model is not a reasonable basis in light of the French data on cracking / indications. The lack of explicit language to remove the insulation for visual inspection raises questions on the benefits gained through ASME required inspections.

The Davis Besse corrosion could have been starting within the thickness of the reactor vessel, and therefore leaving no visual boron deposits on the outer surface until the thickness has been fully corroded away. Volumetric inspection is the only method to detect such degradation in the beginning of a cycle. **BAC Guidebook experimental results????**

Regulatory Requirements/Safety Focus

EA 97-414 involving Inconel Alloy 600 RCS instrument nozzle cracking at SONGS 2 and 3 cited the Maintenance Rule (10 CFR 50.65) because of a lack of staff support to cite against the licensee's Technical Specification for reactor coolant pressure boundary leakage. The violation was cited at a Severity Level IV because there was a lack of unanimity as to whether the violation should have been cited as a Severity Level III violation. During the PEC, the licensee presented information in which they asserted that the NRC and industry have recognized that leakages due to PWSCC are not an immediate safety concern because the staff believes that catastrophic failure of a penetration is extremely unlikely. In reference to the Technical Specification requirement proscribing pressure boundary leakage, the licensee quoted from NUMARC 93-01, 9.3.1, which states: "Entry into a Technical Specification Limiting Condition for Operation, although important, is not necessarily risk significant."

The entire licensee argument was focused on the nozzle ejection stemming from catastrophic failure rather than from boric acid wastage.

The proposed order to shutdown Davis Besse by December 31, 2001, cited inspection results at facilities with similar susceptibility ratings as D-B and large uncertainties in the cracking mechanism and extent of cracking at the plants. The NRC staff assumed that RCPBs could be

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compromised at D-B and DC Cook, therefore the December 31, 2001, shutdown was to be required.

It also characterized the Oconee circumferential cracking as "potentially risk-significant condition" that could result in gross RCPB failure and LOCA. The proposed order explained that inspecting for leakage was not sufficient to detect extent of nozzle damage. It clearly stated that VT-2 methods do not provide reasonable assurance that leakage from though-wall flaw would be detected. The proposed order also highlighted other shortcomings of the ASME code inspection requirements: no insulation removal, NDE not required, head cleanliness not addressed.

The proposed order gave the basis for establishing the shutdown date of 12/31/2001: need to get additional information, time to perform inspections, and make needed repairs. Near term inspections required due to damage detected in other plants and uncertainties/variability in plant susceptibilities. "Operation of facilities considered to be highly susceptible to this cracking phenomenon beyond December 31, 2001, is unacceptable unless the recommended inspections to identify this potentially hazardous condition are completed and found acceptable by the staff." However, the proposed order attempted to provide, in part, a risk-based argument for the unacceptability of operation past December 31. The staff cited B&W design-specific information, D-B TS3/4/4/6 for pressure boundary leakage and applied risk-informed decision criteria in RG 1.174: small in crease in CDF, basis for licensee's risk estimate could not be verified without inspection.

The staff linked GDC 14, 30, 32, but these were not to be the central focus of the shutdown requirement.

3.4.1.2 Recommendations

3.4.1.2.1 Recommendations for NRC

- The NRC staff should move to have the ASME Code requirements for inspections of reactor vessel heads, including nozzle penetrations, strengthened (NRR)
- Reassess containment leak rate limit (1 gpm) from RCS
- Establish clear enforcement policy for RCS leakage
- Should not grant enforcement discretion for nozzle cracking

3.4.1.2.2 Recommendations for Industry

- The industry should work with the NRC to strengthen the ASME Code requirements for inspections of reactor vessel heads, including nozzle penetrations
- Consider adopting the French VHP inspection program that accounts for length of cycle, depth of indications observed, and requiring 2 types of volumetric inspections to overcome the weakness of the visual inspection.

- The staff and industry should consider revising ASME code to require that class 1 bolted connections show no leakage at the system pressure test following refueling outages.

3.4.2 (ep) The NRC Failed to Provide Adequate Reactor Oversight Process Guidance

3.4.2.1 Detailed Discussion

The NRC reactor oversight program is structure to use a risk-informed approach to assessing safety performance. The Davis-Besse situation has demonstrated weaknesses in the application of the risk-informed approach to oversight and that additional guidance may be needed to ensure that the program is effectively implemented

Risk-Informed approach

The LLTF found that the staff was having difficulty characterizing the significance of the avis-Besse event. This difficulty appeared to stem from technical limitations of risk assessments and SDPs in that pressure boundary integrity does not appear to be treated explicitly in PRAs. As a result, the type and extent of wastage of the RCS pressure boundary encountered at Davis-Besse appeared to be more within the scope of traditional deterministic analyses than in a risk-informed framework. In fact, as of the time of the LLTF review, the SDP for this event had been in progress for 5 months, with no resolution. Members of the NRC staff expressed the opinion that, in the transition to the ROP, the agency has placed an over-reliance on risk information as opposed to deterministic methods.

Inspector Perceptions

A lack of experience, coupled with the structured nature of the ROP program, and several events during 1998, may have led the inspectors to focus on issues and inspection items that they determined to be of greater significance than the symptoms that DB was experiencing.

The following are observations from task group interviews with the NRC Resident Inspectors:

One RI was not aware of reactor head boric acid issues, but PCAQ 98-0767 was initiated on 4/25/98, which stated that boric acid was on the reactor head, several fist sized clumps and a light dusting of boric acid found. However, several issues were demanding his attention in 1998.

One RI appeared to be highly focused on managing the ROP effort Monitored both baseline hours and number of activities. Didn't follow up during 12RFO to review licensee activities with the head (trusted, but didn't verify) because he thought licensee was pursuing the identification of the leak (false sense of security from RC2 issue). Resident training during an outage suffered due to the focus on ROP implementation and the large number of activities that needed to be followed RI was aware of 1998 CR in 12RFO which identified boric acid on the head, but was not surprised to hear it because of the previous problems with CRDM flange leakage. One RI had limited containment inspection experience...Davis Besse is the only containment he toured.

One RI had limited experience, and was not qualified as inspector until after 2000 refueling outage, Davis Besse was the only containment he toured. The RI conveyed that many things could not be done because ROP wouldn't allow it. More experience may have allowed him to recognize the significance of some items such that they could be folded into the ROP. He had never closed a power reactor open item. Felt the ROP limited his ability to spend much time in containment

Inspection Program

The task group found that the inspection program did not maintain adequate oversight of the boric acid control program at Davis Besse. A significant contributing factor was that the inspection procedure resulting from Generic Letter 88-05 was not fully implemented as intended The final draft of Inspection Procedure 62001was forwarded by Materials and Chemical Engineering Branch (MCEB), to the Inspection and Licensing Program Branch, NRR, on April 29, 1991, for issuance. Section -04 (Inspection Resources) stated that the procedure should be performed once every other refueling outage and will require approximately 8 hours of direct inspector effort.

The version of IP 62001 issued by ILPB on August 1, 1991, deleted the requirement that the procedure be performed every other refueling outage.

The cover memo from MCEB to IPLB also stated that based on comments from the regions, the number of DIE hours in the draft IP should be changed from 8 to 16. This recommendation was by MCEB was not incorporated. The issued IP remained at 8 hours.

The MCEB cover memo stated that MCEB, "recommended that the procedure be incorporated into the inspection program as a separate, stand alone procedure, rather than include it in the core of the existing procedures."

The task group also found no evidence that inspection procedure 62001 was used at Davis Besse. The task group did find examples of its use in other regions. For example, RIV conducted 62001 inspections. Reference ANO report 92-23, which documented a 1-week inspection of BACC program at ANO for follow up of GL 88-05 per IP 62001.

************Joelle input begins**

The LLTF concluded that the NRC failed to provide adequate reactor oversight guidance following the evaluation of numerous light-water reactor inspection program documents, and the performance of interviews with NRC personnel directly involved in the inspection and oversight of Davis-Besse.

NRC inspection procedures were not consistently maintained and implemented at each operating facility. Inspection procedure 62001, Boric Acid Corrosion Prevention Program, was issued August 1, 1991, and subsequently canceled on January 17, 2001. This inspection procedure ensured that the licensee had a program in place to assess leakage from systems containing boric acid. The inspection resources section of procedure 62001 stated that implementation would require 8 hours of direct inspection effort; however, the LLTF did not identify any inspection performed at Davis-Besse using inspection procedure 62001. In addition, some staff members indicated that they felt that there were not enough hours allocated to complete boric acid program inspections

ROP Manual Chapter Attachment 71111.20, Refueling and Other Outage Activities, does not specifically require nor recommend a containment structure closeout inspection This non-routine inspection would be performed as an added component of Manual Chapter 2515, Appendix D, Plant Status, under the Plant Tours section, increasing the number of hours expended for implementation of Plant Status, a non-direct inspection effort, while not reducing the burden of the additionally required 70-100 hours of 71111.20 outage inspection that impacts the resident staff during a scheduled refueling outage. The LLTF concluded that the implementation of the ROP hours and sample sizes, during high activity times, may be a challenge with limited resources.

Review of Manual Chapter 2515, Appendix D, Plant Status, evidenced a lack of specific guidance on the level of detailed review expected for the corrective action documents routinely initiated by the licensee. A senior resident inspector assigned to Davis-Besse indicated in an interview that he was not aware of reactor head boric acid issues; however, a specific Davis-Besse corrective action document (PCAQ 98-0767), which described several fist-sized clumps of boric acid on the head, was written during his tenure. The LLTF concluded that the daily senior resident inspector focus on the licensee's corrective action program was not adequate to ensure that this significant plant issue was identified for review by the inspection program.

Limited experience, coupled with the structured nature of the Reactor Oversight Program (ROP), and several Davis-Besse events during 1998, may have led the inspectors to focus on issues and inspection items that they determined to be of greater significance than the reactor coolant system leakage symptoms that Davis-Besse was experiencing. Interviews indicated that a significant focus was placed on managing the ROP effort at the site. The inspectors used self-developed programs to monitor both baseline hours and the number of activities sampled. During the 2000 outage, the resident inspector was not yet qualified to perform independent inspections; the senior resident inspector indicated that the training of his resident inspector suffered due to his focus on ROP implementation and the large number of activities that needed to be followed. One of the inspectors conveyed that many things could not be done because the ROP would not allow it. The LLTF concluded that more experience may have allowed the inspectors to recognize the significance of some items such that they could be folded into the ROP for inspection and keep implementation of the ROP during the outage from becoming a distraction.

One of the inspectors conveyed that the ROP limited his ability to spend much time in containment. For two of the interviewed resident inspectors, Davis-Besse was the only reactor containment structure that they had experience inspecting. The LLTF considered their lack of breadth of experience in this area to be a detriment to their ability to make an experience-based judgement, or comparison, of the equipment condition in the Davis-Besse reactor containment.

Risk information may be misapplied in various activities. Risk informed regulation of NRC licensed commercial nuclear facilities includes decisions on allocation of inspections, assessment of the risk significance of occurrences, and the assessment of the severity of regulatory violations. Based on interviews with the staff, the LLTF was concerned that risk models do not appropriately account for degradation of passive components. Some of the staff perceived that the NRC has become risk-based as opposed to risk-informed, that issues cannot be pursued without having a risk number attached to them, and that deterministic safety requirements have been discounted.

The LLTF found that the staff was having difficulty characterizing the significance of the Davis-Besse event. This difficulty appeared to stem from technical limitations of risk assessments and SDPs in that pressure boundary integrity does not appear to be treated explicitly in PRAs. As a result, the type and extent of wastage of the RCS pressure boundary encountered at Davis-Besse appeared to be more within the scope of traditional deterministic analyses than in a risk-informed framework. In fact, as of the time of the LLTF review, the SDP for this event had been in progress for 5 months, with no resolution. Members of the NRC staff expressed the opinion that, in the transition to the ROP, the agency has placed an over-reliance on risk information as opposed to deterministic methods

The structure of the reactor oversight process (ROP) doesn't allow the implementation of non-baseline inspections unless a greater than green finding is identified. Prior to this event, all ROP Performance Indicators were green, indicating a lack of risk-significant issues at Davis-Besse. Following the event, the NRC staff has taken several months to characterize the significance determination process (SDP) risk significance of this Davis-Besse condition. Subsequent to the identification of the Davis-Besse head degradation, Region III invoked Manual Chapter 0350, Oversight of Operating Reactor Facilities in a Shutdown Condition with Performance Problems, without meeting the prerequisites of the procedure. Specifically, Davis-Besse performance was not degraded into the multiple/repetitive degraded cornerstone, or the unacceptable performance columns of the action matrix. The LLTF concluded that timeliness of completion of risk assessments and the procedural inability to consider a significant issue independent of the recent plant risk history, provided an environment such that this issue could be viewed as significant from a deterministic perspective, yet staff would have limited procedural guidance for further NRC action.

NRC enforcement focus was shifted by the risk-impact of the issue and enforcement actions were not implemented consistently due to differing staff views. Enforcement (EA 97-414) was issued citing the Maintenance Rule (10 CFR 50.65) involving Inconel Alloy 600 RCS instrument nozzle cracking at SONGS 2 and 3 due to a lack of staff support for enforcement against the licensee's Technical Specification for reactor coolant pressure boundary leakage. In addition, the staff issued the citation as a Severity Level IV, versus a Severity Level III when the staff could not come to full agreement. The licensee presented an argument that was focused on nozzle ejection stemming from catastrophic failure rather than from boric acid wastage.

Lessons learned weren't learned from previous lessons learned reviews (Millstone, IP2, South Texas).

PI&R? No OBF...Bob?

Operating Experience guidance? Gcs?

Barrier Integrity?

3.4.2.2 Recommendations

3.4.2.2.1 Recommendations for NRC

- NRC should conduct more inspections on passive components
- Consider allowing open items for follow up inspections in ROP
- initiate GC-specific inspection procedures and incorporate GC references in Ips
- Assess ROP to allow inspections of items not on list
- Focus more inspection resources on outage periods
- Incorporate guidance for threshold of sensitivity to RCS leakage
- Review inspection guidance for outages with attention toward time in containment
- Establish basis for using deterministic SDP criteria (e.g., barrier integrity cornerstone?)
- Revise and implement IP 62001
- **SEE RECOMMENDATIONS LIST FOR OTHERS**

- Review the risk-informed regulatory framework, clearly define which activities should be addressed by risk-informed methods and which should be addressed be addressed by deterministic methods, and establish a means to evaluate the deterministic methods.

- Re-evaluation of the implementation of the ROP hours, sample sizes, and resources during high activity times is necessary.

- Consideration should be given to proceduralizing "good practices" such as containment building tours.

- Improvements to the ROP are necessary to minimize the opportunity for recurrence of this type of issue. Some recommendations provided for consideration are as follows:

  - Reactivation of procedures 90700 and 62001;
  - Develop guidance for inspection of changing work scope;
  - Evaluate ROP guidance to allow samples of lower risk systems/components;
  - Inspection of containment components when accessible;
  - Inspection guidance for head inspections (i.e. SG guidance);
  - Revisit the policy of not aggregating risk issues/subparts;
  - Use of traditional enforcement for cross-cutting issues;
  - Assess feasibility of predictive PIs and inspections;
  - Consider risk of repetitive LCO entries and develop inspection guidance;

- Improve ROP guidance to encourage inspection of temporary mods, workarounds, etc that may not appear on licensee lists;
- Develop inspection guidance for review of deferred mods, mode restraints during outages, and inspection of plant hardware for age-related degradation;
- Develop inspection guidance to focus on repetitive multiple tasks for significance (i.e. CAC cleaning/ALARA);
- Develop inspection guidance for resident inspector samples of licensing requests to understand the basis and provide necessary feedback to the project manager;
- All cited NOVs should be reviewed during the PI&R biennial inspection
- Inspection guidance to sample all electronic media (videos, etc) ;
- Develop guidance for threshold of sensitivity to RCS leakage, absolute value and trend changes;

Develop guidance to inspect commitments and closure actions;

- # PI&R guidance should be strengthened: Handoff of issues to the PI&R team; Selection of issues; Review of lic binning;

- #With aging plants, do more inspection hours on passive components

- #Develop NRC criteria for inspection of industry initiatives. Provide inspection guidance to address selected industry operational experience. Initiate GC-specific inspection procedures. Incorporate GC references in inspection procedures

- #Discussion threshold for mid-cycle/end of cycle review assessment

- # Evaluate barrier integrity cornerstone inspection to determine if improvements are needed. Develop usable barrier integrity performance indicators

- # Should have independent identification reviewed as part of problems as part of PI&R inspections

- # Do more inside containment inspections as part of License Renewals

3.4.2.2.2 Recommendations for Industry

None.

NOTE: # recommendations are not supported with facts in the documentation portion...

3.4.3 (p) The Industry Failed to Provide Adequate Guidance for Detecting and Correcting Alloy 600 Nozzle Cracking and Boric Acid Corrosion

3.4.3.1 Detailed Discussion

The industry effort to address boric acid corrosion control provided general guidelines to licensees to establish their programs that was based on conducting a few exploratory tests to gage the potential for damage due to boric acid corrosion. However, the extrapolation of the test results and the underlying message may have de-emphasized plant vulnerability to a significant mode of corrosive attack.

The Electrical Power Research Institute (EPRI) and Nuclear Maintenance Application Center (NMAC) joined to provide assistance to the utilities in addressing the requirements of Generic letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR plants," issued in March 1988. The EPRI "Boric Acid Corrosion (BAC) Guide Book," issued in April 1995 was the product of this joint effort. A subsequent revision to the Guide Book was issued in November 2001. Its objective was to provide a single source of comprehensive information to help utilities address plant boric acid control and general leakage reduction issues.

In the initial edition of the book , Section 6 2 addresses detecting leakage during operation. The Containment Air Particulate Monitor was identified to have the capability to monitor 0.1 gpm assuming normal primary system activity and no failed fuel. The containment Air Cooler Condensate Monitors were referred to as another system capable of providing clear, sensitive information. Continued clogging of containment air coolers and the containment monitor filter clogging were important indications of RCS leakage. This condition prevailed even after 12RFO when CRDM flange leakage was addressed through repairs.

The BAC Guide book draws a conclusion (Section 8.3.3 in Revision 1 and 8.1.2 in Revision 0) that " It is hypothesized that, under certain conditions, boric acid deposits on the vessel head actually protect the surface from corrosion by keeping the water away from the surface. ... If the leakage rate is low and its source is above the Boric Acid deposits, heat transfer through the deposits will evaporate the incoming water and thereby keep the surface dry. On the other hand, if the leakage rate is high or if the source is located within the boric acid deposits, the deposits will be wetted, leading to high corrosion rates at the vessel head. " The last sentence clearly explains what may have happened at Davis Besse. However, the illustration of this problem is given to a sketch with a mount of boric acid deposits building up from a flat surface as result of dripping boric acid from the top. Reactor Vessel head penetration cracking was a well known problem for more than two decades and the Industry should have analyzed the worst case scenarios as it relates to reactor vessel head.

The BAC Guide Book Revision 1 Section 4.7 discusses the various tests performed by EPRI and CE . The CE tests were performed with nozzle pointed downwards contrary to the plant application. The EPRI tests had the nozzles mounted upwards and the tests demonstrated that the maximum corrosion depth is near the point where the borated water is injected into the annulus. The assessment further states that " **Corrosion occurring at this location would not be seen during the visual inspection of the vessel surface,** although boric acid deposits on the metal surface would indicate that there has been a leak. " This corrosion rate was experimented further to understand worst case scenarios. The surface deposits and its quantity would depend on the rate of leakage and the rate of corrosion. Leaving rusty deposits on the surface while corrosion continues in the inner layers appear to be a clear possibility. After having identified this critical vulnerability and recognizing the wide range of corrosion rate, the industry remained contented with a visual inspection that did not require the removal of the Vessel head insulation.

NUMARC position on CRDM VHP cracking was discussed in the June 16, 1993, letter to NRC. The letter forwarded the PWR OG safety assessments of VH penetration cracking. Reports concluded that cracking was not an immediate safety concern. NUMARC added that if a through-wall crack would occur, the BA deposition expected would be detectable by inspection activity conducted IAW GL 88-05. NUMARC believed that detection of leakage would prevent any significant BA-induced wastage that would challenge ASME limits.

This was a relatively early indication that a connection was made between VH penetration cracking and the potential for head wastage. However, reliance on GL 88-05 programs downplayed the potential effects.

The NEI letter to NRC dated May 24, 1995, provided status of industry activities related to VHP cracking. It discusses pilot plant inspection results, refers NUREG/CR-6245, OG safety evaluations, GL 88-05 programs, crack growth rate model development, and re inspection efforts. However, it did not alter the attitude of the low safety significant associated with VH degradation.

B&W, nor the OG made formal recommendations to licensees in the areas of RCS leakage or BAC control, and specifically for GL follow up. The task group determined from interviews with industry representative that B&W has not issued any formal recommendations to licensees in the areas of boric acid control, RCS leakage or leak detection (One individual's recollection after 14 years at Framatome). He remembers no follow up on GL 88-05 by the B&WOG. He referenced BAW-2301 as the B&WOG follow up to GL 97-01 {Review BAW-1403 for guidance to licensees.}

3.4.3.2 Recommendations

3.4.3.2.1 Recommendations for NRC

- NRC needs to assign technical project managers to evaluate industry tests and review the widely distributed guidelines for its adequacy and suitability.
- bare metal inspections of systems containing boric acid ???
- establish criteria for accepting industry resolution of Gcs
- NRR should work with industry to develop guidance for voluntary initiatives

3.4.3.1.2 Recommendations for Industry

- Industry focus on VHP cracking needs further tests to conclude on the adequacy of inspection program
- reassess crack models
- assess other areas with A600 nozzles/materials
- EPRI review/revise guidance
- attendance of plant staff at Owner's Group meetings
- Framatome should sensitize its staff to BA corrosion
- conduct cost/benefit analysis of RPV head inspections (dose, cost, time)
- B&W OG should improve dissemination of information to members and hold members accountable for following guidance/recommendations

3.4.4 (cp) The NRC Failed to Establish Adequate Procedures and Guidance to Address the Implications of Alloy 600 Nozzle Cracking and Boric Acid Corrosion

3.4.4.1 Detailed Discussion

The NRC did not provide clear procedures and guidance to address boric acid corrosion implications. In part, this deficiency led to a lack of emphasis by Industry to devote the appropriate level of significance to the problem.

Generic Issues Process

The Generic Issues Program is the primary process for addressing a regulatory matter involving the design, construction, operation, or decommissioning of several or a class of , NRC licensees that is sufficiently addressed by existing rules guidance or programs. NRC management directive 6.4 "Generic Issues Program" is the agency procedure governing this process and it is managed by the Office of Research.

The program allows candidate issues to be initiated from anyone internal or external to NRC. The interviews with the staff members conducted by the task group clarified that roughly 80 percent of the issues have been developed from issues in NRR user needs requests.

The excessive back log on the issues to be processed became a de-motivating factor and therefore bringing new issue was strongly discouraged by the management. Out of the 200 Topic Evaluations conducted soon after AEOD phase out , only one item was studied. Foreign operating experience had become a frequent subject of study during the AEOD function. One study was completed in September 1994 on the subject area and was published as NUREG-CR 6245. While this process may not be implemented with sufficient diligence, a foreign event was studied in the recent past (Manshaan - electrical event) to indicate the process that is still functioning. It appears that the procedure that was left to everyone for initiating input became nobody's business. The significant reduction in staffing for evaluating operating experience may have been another plausible reason for oversight on this matter. The informal judgements on the level of safety significance (mind-set)by the management on the circumferential crack at Bugey-3 in early nineties appear to have played a dominant role in pursuing any further study on this matter. The interviews further revealed that lack of a systematic central review of US and foreign experience could be the reason for not focusing on the critical issues that have generic implications.

Generic Communications

The quantity of Generic Communications produced was not consistent with the number of events being reported via LERs. Some years having several events resulted in no Generic Communications being issued. For example, 1989, 1992, 1998, 1999, and 2000 had several events reported (7, 6, 6, 4, and 7 respectively) with no generic communication being issued. A rapid increase in the number of LERs involving boric acid corrosion and leakage was experienced for the period 1996 through 2001. See Figure Boric10.

NRC Response to Licensee Guidance

Licensee Opportunities to identify RCS leakage were provided in the Boric Acid Corrosion Guide Book In April 1995, EPRI published Boric Acid Corrosion Guidebook to help the industry to implement an effective Boric Acid control program. Under **methods to detect leak rates less than about 0.1 gpm** (section 6.2.2) two specific guidelines were given. Containment air cooler thermal performance as observed in coil heat transfer degradation and consideration for monitoring the boric acid concentration in the containment air cooler condensate.
Under other potential indicators, there reference to observing high containment particulate reading.

The NRC did not review the EPRI guidance.

NRC Action plan

The NRC issued an action plan in 1991to address PWSCC of Inconel 600 components In 1992 and 1993, the staff issued status reports on action plan to track industry activities. Action plan is referenced in GL 97-01 Staff action plan to address PWSCC of Inconel 600 components is documented in a memo from Richardson to Russell (dated Dec. 12, 1991). Specifics 7 future activities. Mar. 24, 1992, memo from Wiggins to Richardson and Nov. 30, 1993, Taylor to Commission did not clearly indicate the disposition of the 7 activities

Inspector knowledge/skills (more on this in section 3.3.5)

Knowledge and skill has a direct relation to recognizing problems The Oconee Circumferential crack, VHP cracks at 4 different foreign countries, etc., were known to the NRC management. The French VHP inspection program was shared with several NRC managers..Foreign experience, or Oconee experience was not considered for Generic Issues Program or shared with the technical staff (one staff member knew this, but he was taken off the continued responsibility)

Recommendations should go to 3.3.5
- Tech staff was denied opportunity for training based on the justification that "we are the experts"A central core of operating experience group should participate and screen both foreign & US plant events/technical issues.
- Average skill level is declining. Preserve speciality skills and offer opportunity for generalists (resident inspectors, managers, etc.,) to receive training from in-house experts.
- Offer increased opportunities for tech staff to engage in continuous learning

3.4.4.2 Recommendations

3.4.4.2.1 Recommendations for NRC

- Establish a central operating experience screening group to identify issues for Generic Issues Program based on US and foreign experience
- evaluate/revise guidance for proposed Gcs
- determine if screening criteria for candidate GIs are acceptable
- assess consolidation of Gcs/GIP
- Ensure that generic requirements or guidance are not eliminated or undermined when making changes to regulatory processes (e.g., deleting inspection procedures)
- update MD 5.5, 6 4, LIC 503
- enhance criteria for BACC program

3.4.4.2.2 Recommendations for Industry

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APPENDIX B - LIST OF ACRONYMS

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APPENDIX C - LIST OF DOCUMENTS REVIEWED

NO. JD	TITLE
6015	IP2 Lessons-Learned Task Group Report
6016	STP Lessons-Learned Report
6017	Millstone/Haddem Neck Lessons-Learned and/or Task Action
6030	Industry guidance document for managing NRC commitments
6037	NRR Office Instructions for code relief requests, exemptions, amendment requests, etc.
6052	Copy of November 19, 1993 NRC letter
6054	NUMARC 93-01, Section 9.3.1
6051	NUREG referenced in AIT report
6053	NRR Operating Instructions LIC-100, LIC-101, LIC-403, LIC-500
	NUREG 1801, Generic Aging Lessons Learned (GALL) Report, April 2001
	FENOC letter to NRC dated November 15, 2000, Commitment Change Summary Report
	NEI 99-04, "Guidelines for Managing NRC Commitment Changes,"
	COM-204, "Interfacing with Owners Groups, Vendors and NEI,"
	License Amendment 234
	License Amendment 180
	NRC letter to FirstEnergy, "Generic Letter 97-01, "Degradation of CRDM/CEDM Nozzle and other Vessel Closure Head Penetrations": Review of the Responses for the Davis-Bese Nuclear Power Station, Unit 1," November 29, 1999
	memorandum from the Division of Engineering to the Division of Licensing, dated June 14, 1999.
	memorandum from the Division of Engineering to Inspection and Licensing Program Branch, April 29, 1991
	NRC letter to the licensee dated February 8, 1990
	GL 97-01 closeout letter dated November 29, 1999
	memorandum from the Division of Engineering to the Division of Licensing Project Management, dated June 14, 1999
	NRC inspection reports 98005 and 98007
	FENOC RAI response (Jan 14, 1999)
	memorandum from the Division of Engineering to Inspection and Licensing Program Branch, April 29, 1991
	final version of Inspection Procedure 62001 issued on August 1, 1991,
	memo from Richardson to Russell (dated December 12, 1991
	Mar. 24, 1992, memo from Wiggins to Richardson and Nov. 30, 1993, Taylor to Commission

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1. BACKGROUND INFORMATION

To determine whether Davis-Besse was an outlier with respect to boric acid leakage operating experience, domestic and international operating experience was reviewed for the period 1986 through the first quarter of 2002. For the period of interest, 73 Pressurized Water Reactors (PWRs) were included in the sample. NRC Generic Communications relevant to boric acid issues that were issued since 1980, were also reviewed to determine what guidance was provided to the industry, and whether or not this guidance was utilized by Davis-Besse

2. DOMESTIC BORIC ACID LEAKAGE OPERATING EXPERIENCE

A review of operating experience relevant to boric acid leakage and corrosion in PWRs was accomplished for the period 1986 through the first quarter of 2002. This information was entered in a database which was then sorted to determine any trends and patterns. Licensee Event Reports (LERs) were the basic source of boric acid leakage events. Other events were added to the database if recorded in an NRC document. Each operating experience document may have discussed more than one component, system, or power plant that was affected Besides listing the component that was affected by the boric acid leak, other information was sorted by NSSS designer, design type, plant operating age, number of operating years at the time of the event report, and year of occurrence.

2.1 Numerous Boric Acid Leakage and Corrosion Events Have Been Documented

Figure 1, "Reported Areas Involving Boric Acid Leakage (1986-2002)" lists the component experiencing a boric acid leak, or was affected by a boric acid leak. As seen by the figure, the most prominent events involving boric acid leakage included 15 documents relating to control rod drive mechanisms (CRDMs), 13 documents relating to reactor coolant system (RCS) nozzle leaks, 9 documents relating to pressurizer (PZR) instrumentation nozzle leaks, 7 RCS valve leaks, 7 RCS instrumentation leaks, and 7 PZR heater leaks. Other less prominent events include four documents relating to corrosion of the steel containment vessel, four events relating to RCS nozzle leaks, three events involving wastage of the reactor pressure vessel (RPV) head, three events involving wastage of the pressurizer.

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Figure 1 Reported Areas Involving Boric Acid Leakage (1986-2002)

2.2 Number of Operating Years Prior to Discovery of a Boric Acid Event is Random when considering all components

Figure 2, "Number of Operating Years Prior to Event Occurrence," displays an even distribution of boric acid leakage events. Figure 2 lists the plants that have reported a boric acid leak and the number of years of operation to the time that the leak was discovered. When taken as a group, it appears equally likely to have a boric acid leak after only a few years of operation, as it does after a long period of operation. In general, however, smaller components take longer to develop a leak than do the larger components. This observation is evident in subsequent figures.

Figure 2, Number of Operating Years Prior to Event Occurrence

2.3 Babcock and Wilcox and Combustion Engineering Plants are highly susceptible to boric Acid Leakage and corrosion

As shown in Figure 3, "Percent of NSSS Design Manufacturers Reporting Boric Acid Leakage" Babcock and Wilcox (B&W) and Combustion Engineering (CE) plants appear to be highly susceptible to boric acid leakage and corrosion. One hundred percent of B&W plants have reported boric acid related problems. Given the high incidence rate of boric acid leakage problems at B&W plants, Davis-Besse should have been alerted and taken appropriate corrective actions. Combustion Engineering plants were broken up into the older CE plant design (12 plants total) and the newer CE80 design (3 plants total) to see if any differences were noted. As shown in the figure, 100 percent of the older CE plants reported boric acid leakage problems, while 67 percent of the CE80 design reported boric acid leakage problems.

Figure 3 Percent of NSSS Design Manufacturers Reporting Boric Acid Leakage

2.4 Westinghouse designed plants are less susceptible to boric acid leakage than other PWRs

Figure 3 also shows that the Westinghouse plants were less susceptible to boric acid leakage problems than were other PWR designs. Within the Westinghouse group, there were large differences in operating experience. The older Westinghouse two-loop plants (W2LOOP) faired the best at 17 percent (6 plants total) reporting boric acid leakage problems, while the four loop ice condenser version (W4LIC) faired the worst at 56 percent (9 plants total). The Westinghouse three-loop plant (W3L) had 46 percent (13 plants total) reporting boric acid leakage problems and the Westinghouse four-loop plant (W4L) had 26 percent (23 plants total) reporting boric acid leakage problems.

2.5 Control Rod Drive Mechanism Leakage is dominated by Babcock and Wilcox plants

As shown by Figure 4, "Control Rod Drive Mechanism Leakage," B&W designed plants dominate control rod drive mechanism (CRDM) leakage. There were 15 documents relating to CRDM leakage of which 10 occurred at B&W plants. When considering that B&W plants make up less than 10 percent of the plants within the sample of 73 PWRs, the B&W plants are greatly over-represented. Figure 4 shows the component that had leaked, the specific facility experiencing the leakage, the design type of the plant, and the number of years of operation prior to the event being discovered. The types of boric acid leakage events include CRDM nozzles (dominant failure), spare CRDM canopies, CRDM seal housings, and a CRDM tube housing.

Combustion Engineering is appropriately represented given that CE plants represent approximately 20 percent of the PWR sample of 73, and approximately 20 percent of the CRDM event reports (3 of 15 reports)

Figure 4 Control Rod Drive Mechanism Leakage

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2.6 Control Rod Drive Mechanism Nozzle Cracking and Leakage at B&W plants

Table 1, "CRDM Penetration Cracking Experience at B&W plants," provides information on the crack location on the RPV head, crack type, extent of NDE (other than cursory visuals) on the CRDMs, number of operating years prior to event report, and the event date. Davis-Besse management had ample operating experience from other B&W plants from which to make an informed decision about the potential for CRDM cracking and its impact on it's plant. As shown in Table 1, B&W plants have had 6 percent of their CRDM penetrations develop through wall cracks, 100 percent of B&W plants have had axial CRDM penetration cracks, and 86 percent of B&W plants have experienced circumferential cracking in at least one CRDM penetration In addition, Davis-Besse was aware that all of the other operating B&W plants had experienced axial and/or circumferential CRDM penetration cracking prior to their own discovery of the same in February 2002.

Figure 5 "Control Rod Drive Mechanism Penetration Cracking Timeline for B&W Plants," presents a graphical representation of CRDM penetration cracking for all B&W plants. As shown in the figure, Davis-Besse was the last B&W plant to report cracking. However, had the boric acid crystal buildup that was identified during the 1996 refueling outage, the 1998 outage and the 2000 outage that was allowed to accumulate been removed, it may have been determined that CRDM penetration cracking had occurred long before February 2002. Ample B&W operating experience was available for Davis-Besse to conclude that a whole (RPV) head Inspection was necessary to determine if cracking was evident, but instead made the decision to continue to operate without performing the penetration inspections.

Figure 5 Control Rod Drive Mechanism Penetration Cracking Timeline for B&W Plants ds

Table 1 Control Rod Drive Mechanism Penetration Cracking Experience at B&W plants

CRDM ROW	CRDMs PER ROW	TOTAL	OCO1	OCO3	ANO1	OCO2	CRY3	TMI1	OCO3	DB	PROBABILITY %
1	1	7								1	14% of Row 1 had cracks
2	8	56		2		2			1	3	14% of Row 2 had cracks
3	16	112	1	2		1		1	1		6% of Row 3 had cracks
4	20	140		2	1	1	1	4	3		9% of Row 4 had cracks
5	24	168		3				3	7	1	5% of Row 5 had cracks
THRU WALL CRACK			1	9	1	4	1	3	5	3	6% of CRDMs have experienced thru wall cracks
AXIAL CRACK			YES	YES	YES	YES	YES	YES	YES	YES	100% have had axial cracks
CIRC CRACK			NO	YES	YES	YES	YES	YES	YES	YES	86% have had circumferential cracks
100% INSP			NO	NO	NO	NO	NO	YES	YES	YES	43% of the units had 100% NDE
OP YEARS PRIOR TO EVENT			27	27	17	27	24	27	27	24	
EVENT DATE			12/4/00	2/18/01	3/25/01	4/28/01	10/01/01	10/12/01	11/12/01	2/27/02	

2.7 Components Having the Most Prevalent Boric Acid Leakage Issues

Operating experience was reviewed to determine the average number of operating years prior to discovery. The operating time to leak discovery was determined by comparing the event date with the date that an operating licensee for the plant was obtained from the NRC. Figure 6, "Average Number of Operational Years Prior to Leakage Event for Selected Components," provides several insights to five of the most prevalent leakage areas, CRDM nozzle leakage (15 reports), RCS instrumentation nozzles (13 reports), Pressurizer instrumentation nozzles (9 reports), pressurizer heater sleeves (7 reports), and RCS instrumentation (7 reports). Most reports contained multiple occurrences of leakage. These events and the operational experience to be gained were available to

Davis-Besse to learn from. Davis-Besse relied heavily on industry models to postpone CRDM penetration inspections. As shown from the operational experience data, Davis-Besse was within the average operating time period to expect CRDM penetration cracking and leakage. The industry average operating time for CRDM penetration leakage is 21.6 years. The operating time period for Davis-Besse's discovery of leakage was 24 years, which exceeded the average time period.

Figure 6 Average Number of Operational Years Prior to Leakage Event for Selected Components

2.8 Reactor Pressure Vessel Metal Wastage Events Caused by Boric Acid Corrosion

Figure 7, "Reactor Pressure Vessel Head Base Metal Wastage Events," shows those plants which have experienced corrosion (beyond surface metal corrosion). The figure also shows the operating years prior to event occurrence. The Turkey Point 4 event in March 1987 was the major reason for issuing IN 86-108 Supplement 1 in April 1987, and the Salem 2 event in August 1987 was the major reason for issuing IN 86-108 Supplement 2 in November 1987. Both of these events and their lessons learned from 1987 should have been an acknowledged precursor to the Davis-Besse event discovered in February 2002. A mind set had developed at Davis-Besse and the NRC that boric acid corrosion on the RPV head, because of its elevated temperature, was not a credible event

Figure 7 Reactor Pressure Vessel Head Base Metal Wastage Events

2.9 Pressurizer Vessel Wastage Events Caused by Boric Acid Corrosion

Figure 8, "Pressurizer Vessel Base Metal Wastage Events," shows those plants which have experienced corrosion (beyond surface metal corrosion). The figure also shows the operating years prior to event occurrence. These events and their lessons learned should have been an acknowledged precursor to the Davis-Besse event discovered in February 2002. Similar to comments made about boric acid corrosion of the RPV head, operating experience does indicate that boric acid corrosion of high temperature components is possible, and should be assessed.

Figure 8 Pressurizer Vessel Base Metal Wastage Events

2.10 Reactor Coolant System Nozzle Leakage Operational Experience

Miscellaneous RCS nozzle leakage has occurred in varied locations. Figure 9, "Reactor Coolant System Nozzle Leakage Events," shows that the larger nozzles take longer to develop leakage. The figure would also show that no one NSSS vendor dominates. Repetitive leakage from similar components is not evident.

Figure 9 Reactor Coolant System Nozzle Leakage Events

2.11 Westinghouse Plants Dominate Reactor Coolant System Instrumentation Leakage

Although RCS instrumentation leakage has occurred at B&W and CE designed plants, Westinghouse plants dominated with five out of seven recorded events. Once again, the recorded events do not show indications of repetitive failures of similar components. Two of the events occurred on Westinghouse three loop plants, while three event occurred on Westinghouse four loop plants. See Figure 10, "Reactor Coolant System Instrumentation Leakage" for a brief description of the event and the number of years of operation prior to each event. Of note is that five of the seven event took between 15 and 20 years to develop.

Figure 10 Reactor Coolant System Instrumentation Leakage

2.12 Combustion Engineering Plants dominate Pressurizer Instrumentation Nozzle Leakage

As shown in Figure 11, "Pressurizer Instrumentation Nozzle Leakage," CE plants dominate the recorded events. Seven of nine pressurizer instrumentation nozzle leakage events occurred at CE plants. Most of the events involved pressurizer level instrumentation. Most (5 of 8) of the pressurizer instrumentation events occurred between 11 and 14 years of operation.

2.13 Combustion Engineering Plants Accounted for All Reported Pressurizer Heater Sleeve Leakages

Figure 12, "Pressurizer Heater Sleeve Leakage," shows a dominance by CE with 100 percent (7 of 7) of the events. The event occurring at Calvert Cliffs 2 was extensive, involving 28 of 120 leaking sleeves. Leaking boric acid from the Calvert Cliffs event also resulted in corrosion damage to the carbon steel base metal of the pressurizer. Other events involving pressurizer heater sleeves were less severe and involved one or two sleeves

Figure 11 Pressurizer Instrumentation Nozzle Leakage

Figure 12 Pressurizer Heater Sleeve Leakage

2.14 Combustion Engineering Dominates Reactor Coolant System Instrumentation Nozzle Leakage

As shown in Figure 13, "Reactor Coolant System Instrumentation Nozzle Leakage Events," CE dominates with 10 of 13 events. In addition, most of the events involved more than one leaking nozzle. The review also shows that most of the events involved hot leg nozzles Nine of the 13 instrumentation nozzles occurred between 11 and 16 years of operation. Most of the nozzle cracking was attributed to primary water stress corrosion cracking (PWSCC).

Figure 13 Reactor Coolant System Instrumentation Nozzle Leakage Events

3.0 OPERATIONAL EXPERIENCE INFORMATION AND GUIDANCE PRESENTED THROUGH THE NRC GENERIC COMMUNICATION SYSTEM

Seventeen NRC Generic Communication documents have been issued (including supplements) by the NRC involving boric acid leakage or corrosion caused by boric acid deposits from 1980 through the first quarter of 2002. All of these documents (Information Notices, Bulletins, and Generic Letters) were issued to provide information to the industry and the public concerning recent events of interest. Some of the NRC generic communication documents (bulletins and generic letters) may have also requested that the addressees provide the NRC with requested information regarding plant specific conditions at their facilities, the existence (or non-existence) of certain programs, corrective action implementation status, and inspection status and findings. Many of the issued generic communications have alerted Davis-Besse and the industry to conditions that ultimately resulted in the severe corrosion of the RPV head at Davis-Besse over the last few years, and eventually discovered by Davis-Besse in February 2002.

3.1 NRC Generic Communications Involving Boric Acid Leakage or Corrosion

Sufficient information was issued by the NRC to alert licensees and the NRC to the potential for boric acid corrosion of carbon steel components. Numerous events have occurred since the early 1980s involving primary coolant leakage in PWRs. The primary system leaks occurred because of component failures involving material wastage by boric acid, or through stress corrosion cracking of materials and then subsequent material corrosion by boric acid. Some of these events formed the basis for NRC generic communications.

Table 2, "NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002," provides critical operating experience information relevant to boric acid leakage and corrosion. The information was provided to Davis-Besse, however, Davis-Besse failed to take action and learn from the past experiences of other operating nuclear facilities.

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Table 2 NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002

Generic Com	Title	Issue Date	Abstract	Licensee Requests
IN 80-27	Degradation of Reactor Coolant Pump Studs	6/11/80	Corrosion damage to a number of [illegible] studs on two of the four [illegible] Jackson RCPs at Fort Calhoun. Cause of the wastage is thought to be corrosive attack by hot boric acid from the primary coolant. The condition of the [illegible] discovered at FTC raises concerns that such severe corrosion if undetected could lead to stud failures which could result in loss of integrity of the reactor coolant pressure boundary. [illegible]	None required
IN 82-06	Failure of Steam Generator Primary Side Manway Closure Studs	3/12/82	At Maine Yankee [illegible] by UT to be cracked. Boric acid [illegible]. Reference was made to [illegible] in Calvert Cliffs, FTC, Oconee, and ANO-1	None required
IB 82-02	Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants	6/2/82	Recaps the FTC and Maine Yankee [illegible] problems in IN 80-27 and IN 82-06. Adds [illegible] stress corrosion cracking. At the present time visual examination (e.g. IWA-2210 VT [illegible]) appears to be the only method to detect borated water corrosion [illegible] damage and may require insulation removal and/or disassembly of the component, in some cases in order to have direct visual access to the threaded fasteners	1. Develop and implement procedures for [illegible] 2. Threaded fasteners of closure connections identified in the scope of this bulletin when opened [illegible] shall be removed, cleaned and inspected per IWA-2210 and IWA-2220 of ASME Code Section XI before being reused 3a. Identify those bolted closures of the RCPB that have experienced leakage particularly those [illegible] where leakage occurred during the most recent plant operating cycle. Describe the [illegible] and corrective measures taken [illegible] the problem. If the leakage was attributed to gasket failure or its design [illegible] 3b. Identify those closures and connections [illegible] include types and composition of materials used 4. A written report to the Regional office within 60 days following the completion of the outage during which Action Item 2 was performed. [illegible] 5. [illegible]

IN 86-108	Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion	12/29/86	[illegible]	None required
IN 86-108 Sup 1	Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion	4/20/87	[illegible]	None required
IN 86-108 Sup 2	Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion	11/19/87	[illegible]	None required
IN 86-108 Sup 3	Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion	1/5/95	[illegible]	None required

6/7

GL 88-05	Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants	3/17/88	The principal concern is whether the affected plants can continue to meet the requirements of GDC 14, 30 and 31 of Appendix A when the concentrated boric acid solution or boric acid crystals, formed by evaporation of water from the leaking reactor coolant, corrode the reactor coolant pressure boundary. The GL cites Turkey Point 4, Salem 2, San Onofre 2, ANO-1 and FTC. The GL cites [illegible] [illegible]	(1) Determine the principal locations where leaks that are smaller than the allowable TS limit can cause degradation of the primary pressure boundary by boric acid corrosion, (2) establish procedures for locating small coolant leaks, (3) establish methods for conducting examinations and performing engineering evaluations once a leak is located, and (4) corrective actions to prevent recurrence of this type of corrosion. Responses are required within 60 days of the date of the GL.
IN 90-10	Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600	2/23/90	Alert addressees to potential problems related to PWSCC of Inconel 600 that has occurred in [illegible] at several domestic and foreign PWR plants. During the 1989 refueling outage at CC-2, visual examination detected leakage in 20 pressurizer heater penetrations and 1 upper level pressure tap instrument nozzle. Leakage was indicated by the presence of boric acid crystals. The heater sleeves and the instrumentation nozzles were made of Inconel 600 tubing and bar materials, respectively supplied by [illegible]. All instrument nozzles were made from heat no. [illegible]. On [illegible] a small amount [illegible] observed on a [illegible] diameter upper pressurizer level instrument nozzle at SONGS 3. Two foreign reactors were also cited involving Inconel 600. PWSCC was first reported by Coriou almost 30 years ago. The studies of PWSCC in Inconel 600 have been documented in numerous reports; however, the mechanism for PWSCC in Inconel 600 is still not well understood. It may be prudent for licensees of all PWRs to review their use of 600 connections in the primary coolant pressure boundary and, when necessary, to implement an augmented inspection program.	None required
IN 94-63	Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks	8/30/94	Alert licensees to the potential for significant damage that could result from corrosion of reactor system components caused by cracking of the stainless steel cladding. Severe corrosion damage of the carbon steel casing of a high head safety injection pump at North Anna 1. The damage was caused by cracks through the stainless steel cladding in the pump that allowed corrosive attack by the boric acid coolant. The corrosion had penetrated to a depth about 0.125 inch of the outside surface of the pump (2.5 inches long by 1.5 inches wide by [illegible] inches deep).	None required
IN 96-11	Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations	2/14/96	Alert licensees to the increased likelihood of stress corrosion cracking of PWR control rod drive mechanism penetrations if demineralizer resins contaminate the reactor coolant system. The NRC determined that the safety significance of the cracking was low because the cracks were axial, had a low growth rate, and were in a material with an extremely high flaw tolerance (high fracture toughness). Accordingly the cracks were unlikely to propagate very far. In December 1991, after cracks were found in a CRDM penetration in the reactor head of a French plant (Bugey 3), an NRC staff position was implemented to address PWSCC at all U.S. plants. The NRC [illegible] Nuclear Management and Resource Council [illegible] of PWRs. Each owners group submitted [illegible] safety assessments [illegible] February 1993, through NEI to the NRC, on the CRDM cracking issue. In July 1993 the NEI submitted to the NRC [illegible] efforts for [illegible] identified during inspections of CRDM penetrations. On the basis of [illegible] and the European experience, the NRC concluded that there was a high probability that CRDM penetrations at U.S. plants [illegible] similar axial cracks caused by PWSCC. In 1994 an inspection for PWSCC at a reactor in Spain identified cracks which were apparently initiated by high sulfate levels in the reactor coolant system. 15 of 17 spare penetrations showed stress corrosion cracking and 4 of 20 active penetrations showed stress corrosion cracking.	None required

GL 97-01	Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations	4/1/97	[illegible]	[illegible]
IN 2001-05	Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3	4/30/01	[illegible]	[illegible]

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BL 2001-01	Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles	8/3/01	[illegible]	[illegible]

IN 2002-11	Recent Experience with Degradation of Reactor Pressure Vessel Head	3/12/02	[illegible]	None required

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BL 2002-01	Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity	[illegible]	[illegible]	[illegible]
[illegible]	Possible Indicators of Ongoing Reactor Pressure Vessel Head Degradation	[illegible]	[illegible]	None required

3.2 Operating Experience Events and Issuance of NRC Generic Communications

Figure 14, "Boric Acid Leakage and Corrosion Events VS Relevant NRC Generic Communication Documents," shows that several o/5

years elapsed (with relatively high numbers of primary system leakage or boric acid corrosion events) with no boric acid leakage or corrosion generic communications being issued by the NRC. For example, during the period 1989 through 1994, two INs were issued (IN 90-10 on PWSCC of Inconel 600, and IN 94-63 on boric acid corrosion of a pump casing). No Generic Safety Issue has ever been issued by the NRC involving boric acid leakage or boric acid corrosion. Boric acid leakage events (involving both component cracking and corrosion) during the period 1989 through 1994 and 1996 through 2000 are provided in paragraphs 3.2.1 and 3.2.2.

Figure 14 Boric Acid Leakage and Corrosion Events VS. Relevant NRC Generic Communication Documents

3.2.1 Boric Acid Leakage or Corrosion Events Reported From 1989 Through 1994

McGuire Unit #1 (LER #36989020). On 7/27/89, abnormal degradation of the unit 2 steel containment vessel (SCV) because of corrosion was discovered. The corrosion was caused by standing water in the annulus area. The most significant corrosion occurred in areas where boric acid deposits were also found. The boric acid deposits resulted from leaking instrumentation connections. Similar degradation was found in unit 2.

Catawba Unit #1(LER # 41389020). On 9/21/89, a preliminary visual inspection of the Catawba units 1 and 2 steel containment vessel (SCV) exterior surfaces was performed. The observed corrosion was caused by standing water in the annulus areas. The most significant corrosion occurred in areas where boric acid deposits were also found.

Arkansas Nuclear Unit #1 (LER #31389043). On 12/8/89, while removing the nut ring from beneath the reactor vessel nozzle flange at control rod drive mechanism (CRDM) location I-2, it was discovered that approximately 50% of one of the nut ring halves had corroded away and that two of the four bolt holes in the corroded nut ring half were degraded to the point where there was no bolt/thread engagement.

Millstone Unit #3 (LER #42389031). On November 28, 1989, a loose nozzle ring set screw on the 'C' pressurizer safety valve was found with steam discharging from the set screw location. The nozzle ring, which is held in place by the set screw, is essential in assuring the valve pops fully open. An inspection of the valve revealed that the set screw threads were corroded (by boric acid) or steam cut.

Ft. Calhoun Unit #1 (LER #28592018). On March 20, 1992, severe corrosion of the carbon steel fasteners on the boric acid pump flanges and piping supports was discovered. The root cause of this event was the original design of the flange connections did not anticipate corrosion problems due to boric acid leakage at the system flange connections. The carbon steel fasteners were covered with glued heat tracing and asbestos insulation, thus, sealing the fasteners in a potentially high corrosive environment.

Waterford Unit #3 (LER #38292002). On March 25, 1992, an Unusual Event was declared due to reactor coolant system leakage. The reactor was shut down and the source of the leakage was subsequently determined to be the packing area of reactor coolant hot leg sample valve RC-104. The packing gland studs on RC-104 failed due to boric acid corrosion.

Waterford Unit #3 (LER #38292006). On July 11, 1992, an Unusual Event was declared as a result of reactor coolant system leakage. The reactor was shut down and the source of the leakage determined to be the packing area of Reactor Coolant Hot Leg Sample Valve RC-104. This event resulted from the failure of a temporary leak repair made to RC-104 after the valve's packing gland studs failed due to boric acid corrosion on March 25, 1992.

Seabrook Unit #1 (LER #44392026). On July 14, 1992, it was discovered that three of the four cover bolts on Chemical Volume Control System [CB] demineralizer 2A resin sluice discharge valve, CS-V-93 had fractured. This bolting configuration caused the valve bonnet to loosen and become cocked. It was discovered that two additional valves, CS-V-252 and CS-V-742, in close proximity to CS-V-93 each had two fractured cover bolts. CS-V-93 and CS-V-252 are safety related, ASME Class 3 valves, and CS-V-742 is a non-nuclear safety valve. The root cause of the bolting failures was stress corrosion cracking. North Atlantic has replaced bolting on a total of 158 Xomox Tufline plug valves which had Grade B6 Type 410 stainless cover bolts.

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Millstone Unit #3 (LER #42394012). On September 9,1994, a leak was discovered in 3/4-inch socket weld on a 'C' Reactor Coolant System (RCS) Loop Flow Instrumentation line. The weld was removed for analysis during which liquid penetrant testing identified a circumferential crack approximately, 5/8-inch long. Initial metallurgical analysis indicated that the root cause of the socket weld failure was most probably a weld defect, believed to result from a lack of fusion in the weld root.

Calvert Cliffs Unit #1 (LER #31794003) On February 16, 1994, boron deposits were noticed on PZR heater sleeve B-3 indicating leakage from the RCS The examination revealed a circumferential bulge approximately 0.5 inches long and 0.019 inches high (diametrical) in the area of the boric acid leaks. The most probable cracking mechanism is Primary Water Stress Corrosion Cracking. The source of stress for the cracking was the bulging and axial scratches associated with the removal of the stuck reamer. Corrective Actions included plugging FF-1 with an Alloy 690 plug welded to the outer diameter of the PZR lower head and examining the remaining Unit 1 PZR heater sleeves.

Calvert Cliffs Unit #1 (LER #31794004). On February 21, 1994, a higher than anticipated corrosion of three nuts were discovered on one of the Incore Instrumentation flanges on the Unit 1 reactor vessel head. A subsequent inspection discovered an additional flange with similar degradation. The flanges were known to be leaking slightly since 1993, but repairs were deferred until 1994 because the expected corrosion rate was very low. The excessive corrosion rate was apparently due to the presence of wet boric acid on some of the flange components where we expected only dry boric acid.

Three Mile Island Unit #1 (LER #28994001). On March 7, 1994, TMI-1 located and isolated a body-to-bonnet leak from the pressurizer spray valve (RC-V1). The root causes was boric acid degradation of pressurizer spray valve (RC-V1) fasteners and the failure to consider pre-load when increasing motor operator torque. Corrective actions include an evaluation of corrosion resistant fastener materials, programmatic improvements, and training.

Diablo Canyon Unit #1 (LER #27590010). On July 31, 1990, leakage through a crack in the unit 1 positive displacement charging pump (PDP) suction piping elbow was discovered.

Calvert Cliffs Unit #2 (LER #31894003). On July 11, 1994, a non-isolable Reactor Coolant System pressure boundary leak was discovered. The leak was found to be caused by a 150 degree circumferential crack in a weld in the 22A Safety Injection Tank discharge test connection.

Oconee Unit #3 (LER #28791008). On November 23, 1991, several alarms were received which indicated failed instruments inside the reactor building. The shift supervisor concluded that leakage was approximately 60 to 70 gpm, and declared an alert. The unit tripped from 33% full power due to a control oscillation while attempting to secure a feedwater pump. The leak was determined to be a failed fitting on an instrument line at the top of a steam generator. A total of approximately 87,000 gallons of RCS leakage was confined within the RB.

Surry Unit #2 (LER #28192008). On December 15, 1992, a Reactor Coolant System (RCS) leak had developed near the Low Pressure Letdown Flow Transmitter. The leakage occurred when a section of drain valve tubing for the Low Pressure Letdown Flow Transmitter separated from its

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fitting

Arkansas Nuclear Unit #1 (LER #31390021). On December 22, 1990, a potential Reactor Coolant System leak in the area of a pressurizer upper level instrumentation nozzle was discovered Subsequent inspection using Nondestructive Examination methods confirmed the existence of a small axial crack in the nozzle inner surface which extended to the annulus between the nozzle and the pressurizer shell and breached the outside diameter (OD) of the nozzle at the toe of the nozzle to vessel weld.

Ft. Calhoun Unit #1 (LER #28590028). On December 14, 1990, an investigation of unknown reactor coolant system (RCS) leakage identified the source as installed spare control element drive mechanism (CEDM) housing number 9. Subsequent removal and inspection identified two axial cracks in an inside diameter weld overlay region approximately two feet from the bottom flange of the housing. Similar installed spare CEDM housing number 13 was also removed and inspected, revealing two similar cracks in the weld overlay region.

Point Beach Unit #1 (LER #26690008). On July 20, 1990 unit 1 was shut down to repair leaks in the reactor coolant system with an average total leakage of approximately 0.27 gallons per minute. Reactor coolant was leaking through a canopy seal weld on control rod drive mechanism I-3 and the upstream weld on B steam generator channel head drain line isolation valve 1RC-526B.

Calvert Cliffs Unit #2 (LER #31889007) On May 5, 1989, an in-service inspection of the unit 2 pressurizer discovered evidence of reactor coolant leakage from 28 of the 120 pressurizer vessel heater penetrations and one upper level nozzle. The cause of leakage was intergranular stress corrosion cracking of Inconel 600.

San Onofre Unit #2 (LER #36192004). On 2/18/92, a dye-penetrant examination of a pressurizer vapor space level instrument nozzle revealed the presence of a crack. The examination was prompted by earlier observations of rust and boric acid crystals in the vicinity of the nozzle during a walkdown of the reactor coolant system following the shutdown. A thorough inspection of the unit 2 nozzles, prompted by the findings at unit 3, revealed similar signs of rust and boric acid crystals at two of the nozzles. The observed leakage was attributed to primary water stress corrosion cracking (PWSCC) of the Inconel 600 material.

Palisades Unit #1 (LER #25593011). On October 9, 1993, an inspection of the pressurizer upper temperature nozzle penetration (TE-0101) found it to be leaking. Subsequent inspection of the lower temperature nozzle penetration (TE-0102) found it to be leaking also. The root cause was determined to be primary water stress corrosion cracking of the Inconel 600 nozzle material.

St. Lucie Unit #2 (LER #38994002). On March 16, 1994, FPL Engineering personnel identified trace amounts of boric acid on the exterior of the Pressurizer steam space C instrument nozzle during an inspection. Subsequently, an interior dye penetrant examination was performed and identified unacceptable indications at the A, B and C steam space instrument nozzle welds. The unacceptable weld indications were in the 'J' weld between the alloy 690 nozzle and the clad on the inside of the Pressurizer.

St. Lucie Unit #2 (LER #38995004). On October 10, 1995, an instrument nozzle located on the

'B' side RCS hot leg exhibited an apparent boric acid buildup indicative of RCS leakage. Further investigation confirmed that pressure boundary leakage had previously occurred, most probably due to primary water stress corrosion cracking (PWSCC) of alloy 600 material at the instrument nozzle.

3.2.2 Boric Acid Leakage or Corrosion Events Reported From 1998 Through 2000

Davis-Besse Unit #1 (LER #34698009). On September 9, 1998, two of the eight body to bonnet nuts missing on Reactor Coolant Pressurizer Spray Valve (RC-2). The most probable cause for the two missing nuts on RC-2 is that a packing leak allowed boric acid corrosion of two carbon steel nuts that were inadvertently installed on RC-2 a few months earlier, due to less than adequate material seperation work practices during previous maintenance activities. These nuts were subsequently replaced on September 9, 1998, and September 10, 1998. On-line leak sealing activities were conducted on September 10, 1998, to stop the boric acid leak at RC-2. on October 16, 1998, it was discovered that the second nut, installed on September 10, 1998, was not installed properly. At this same time, it was discovered that an additional nut was degraded.

Beaver Valley Unit #2 (LER #41200003). On December 11, 2000, control room operators received indications of a Primary System leak in the Reactor Containment Building The RCS leak rate was estimated to be between 12 and 20 gpm. The cause of the RCS leakage into the containment building was an abrupt packing leak on a motor-operated (MOV) drain insolation valve on the RCS. The gland stud eye bolts on the RCS primary loop fill and drain valves were replaced with a more stress corrosion resistant material.

Salem Unit #2 (LER #31198007) On July 29, 1998, indications of leakage through reactor coolant system (RCS) instrumentation tubing were discovered. Additional walk-downs resulted in the discovery of leakage indications on the tubing of five other RCS instrument lines and on tubing in the pressurizer liquid sample line delay coil. Small accumulations of dried boron on the outside of the tubing were the only indications of leakage. The failure mechanism is transgranular stress corrosion cracking initiated from the outside diameter due to the presence of contaminants on the outside surface of the tubing.

Cook Unit #1 (LER #31598027). On May 5, 1998, Inspection results identified varying amounts of construction-related debris and boric acid deposits in the Unit 1Containment Spray header and RHR spray header and nozzles. The most probable cause for the boric acid deposits/blockage in the Unit 1 RHR spray piping is inadequate inspection of RHR system piping after a 1979 inadvertent spray actuation.

Surry Unit #1 (LER #28098006). On March 24, 1998, it was noted that there was a boric acid build-up on the head of the RCP lower radial bearing Resistance Temperature Detector (RTD) connection. A sample of the water revealed that the water was from the RCS indicating a through wall leak of the thermowell.

Palo Verde Unit #1 (LER #52899006). On October 2,1999, a small accumulation of boric acid residue was discovered on a reactor coolant system loop 2 hot leg instrument nozzle. The boric acid had accumulated on the exterior of the hot leg piping around the outer perimeter of the instrument nozzle. The Alloy 600 nozzle has been repaired.

Point Beach Unit #1 (LER #26699012). On November 4, 1999, a through-wall defect or flaw on the upstream weld for valve 1RC-526A, the isolation valve for the Unit 1 ~AU steam generator channel head drain. This indication was discovered while conducting an informational liquid dye penetrant examination of that weld due to the visual identification of boric acid crystals on the weld. The weld has been replaced.

Waterford Unit #3 (LER #38299002). On February 25, 1999, Reactor Coolant System (RCS) pressure boundary leakage involving two Inconel 600 instrument nozzles on the top head of the Pressurizer was discovered. Subsequent inspections of the remainder of Inconel 600 nozzles identified 3 more leaking nozzles. One is on RCS Hot Leg #1 RTD nozzle, one is on RCS Hot Leg #1 sampling line, and one is on RCS Hot Leg #2 differential pressure instrument nozzle. The apparent cause of the leaks is axial cracks near the heat-affected zone (HAZ) of the nozzle partial penetration welds resulting from Primary Water Stress Corrosion Cracking (PWSCC). The leaking Pressurizer nozzles have been repaired using a welded nozzle replacement. The leaking Hot Leg nozzles have been temporarily repaired using a Mechanical Nozzle Seal Assembly (MNSA).

Palisades Unit #1 (LER #25599004). On October 16, 1999, moisture and/or boric acid deposits on the exterior surfaces of three CRDM seal housings was discovered. The affected seal housings were removed when plant conditions permitted, and on November 2, 1999, two of the three were determined to have small through-wall cracks. All 45 seal housings were ultimately removed from the head and inspected utilizing visual, PT, and EC examination techniques. The inspections revealed that 30 of the 45 seal housing assemblies contained small circumferential cracks. Three seal housing tubes also contained small axial cracks. Examination of spare housing showed similar crack indications. The cracking has been determined to be transgranular stress corrosion cracking.

Arkansas Nuclear Unit #2 (LER #36800001). On July 30, 2000, twelve pressurizer heater sleeves and one RCS hot leg resistance temperature detector nozzle were found to have been leaking. Leakage was indicated by boric acid accumulation. The root cause evaluation concluded that the failure mechanism was PWSCC of Alloy 600 material.

Palo Verde Unit #2 (LER #52900004). On October 4, 2000, a small accumulation of boric acid residue was discovered on a reactor coolant system pressurizer heater sleeve (Alloy 600). Subsequent eddy current testing confirmed a liner indication in the sleeve.

Waterford Unit #3 (LER #38200011). On October 17, 2000 evidence of leakage was discovered at pressurizer heater sleeve (F-4). The other two cases of leakage were discovered during inspections on October 19, 2000 and involved evidence of leakage at two of the three MNSA clamps that had been installed during the refuel 9 outage as temporary repairs of leaking RCS nozzles. The three leakage cases were due to 1)PWSCC, 2) a MNSA clamp flange not being flat against the pipe and 3) a MNSA clamp seating itself, respectively.

Arkansas Nuclear Unit #1 (LER #31300003). On February 15, 2000, a weld in a Reactor Coolant System (RCS) hot leg level instrumentation nozzle was found to have been leaking as indicated by boron buildup. Cracked welds were later found on the other six hot leg level instrumentation nozzles of similar design. One weld crack was subsurface. The root cause was determined to have been using Alloy 182 weld metal exposed to RCS water in a highly restrained weld joint that had not been stress relieved, resulting in Primary Water Stress

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Corrosion Cracking (PWSCC).

Summer Unit #1 (LER #39500008). On 10/7/00, an accumulation of boric acid near the "A" loop of the RV was discovered. Subsequent inspections revealed small amounts of boron buildup on the weld between the vessel nozzle and the hot leg pipe. A PT examination of the pipe identified a 4 inch indication at the weld approximately 3 feet from the vessel between the hot leg piping and the reactor vessel nozzle. The indication was located about 17 inches from the top of the pipe. Subsequent UT examination from the inside diameter identified an axial flaw less than 3 inches long. The same examination determined that the original indication was not the source of the leak. The PT indication were later determined to be steam cutting/boric acid corrosion at the nozzle butter to nozzle interface.

Oconee Unit #1 (LER #26900006). On November 25, 2000, small amounts of boric acid was found on the top surface of the Reactor Pressure Vessel head. The deposits appeared to be located at the base of 5 (of the 8) unused thermocouple and the #21 CRDM nozzles at points where they penetrate the RPV head surface. On December 4, 2000, an eddy current test was performed on the inside surface of the 8 T/C nozzles and revealed axial crack-like indication on the ID of the nozzles in the vicinity of the partial penetration weld (on the underside of the RPV head). On December 9, 2000, dye penetrant testing on CRDM #21 identified two very small pin hole indications. PWSCC was determined to be the primary failure mechanism of both the T/C nozzles, and CRDM weld cracks.

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4.0Reported Events Involving Boric Acid Leakage, Component Corrosion, and Component Cracking

LER Number 31386006
Plant Arkansas Nuclear Unit #1
Event Date10/23/1986
Abstract power level - 000%. Corrosion of a reactor coolant system (RCS) nozzle and adjacent cold leg piping was discovered during refueling outage performance of RCS inservice inspection. RCS leakage from a body-to-bonnet seal on a normally open isolation valve in the HPI line had run down the stainless steel HPI piping within the reflective line insulation to the carbon steel nozzle and cold leg piping. The leakage was less than 0.10 gallons per minute and had occurred over a period of about 6 months. This continuous leakage, the piping temperatures, and the piping to insulation fitup are believed to have resulted in pooling of what became highly concentrated, corrosive boric acid along the bottom of the nozzle and adjacent cold leg piping. The maximum depth of the corrosion was about ½ inch in the area of minimum HPI nozzle thickness (3/4 inch including the thickness of an interior stainless steel clad) at the HPI line to nozzle weld. The galvanic effect due to dissimilar metals contributed to the severe corrosion in this area. Repairs consisted of grinding the areas of corrosion and performing a weld buildup in the area of the most severe damage. An evaluation and inspection of other components where boric acid attack of carbon steel could occur or previously known sources of borated water leakage was performed with no additional problems found

LER Number 31389043
Plant Arkansas Nuclear Unit #1
Event Date 12/8/1989
Abstract Power level - 000%. On 12/8/89, while removing the nut ring from beneath the reactor vessel (RV) nozzle flange at control rod drive mechanism (CRDM) location I-2, plant maintenance personnel discovered that approximately 50% of one of the nut ring halves had corroded away and that two of the four bolt holes in the corroded nut ring half were degraded to the point where there was no bolt/thread engagement. A total of six CRDM flanges had been identified to be potentially leaking during a video camera inspection on 11/28/89 while the plant was in hot shutdown. After the plant was taken to cold shutdown, maintenance personnel disassembled and inspected the six CRDM flanges which had been identified during this inspection. All of the gasket seating surfaces were found to be undamaged with the exception of I-2. The RV nozzle flange at I-2 was eroded and pitted. An inspection of the flanges and spiral wound gaskets which were removed from between the flanges revealed that the cause of the leaks was the gradual deterioration of the gaskets with age. An engineering Evaluation concluded that the I-2 nozzle flange was acceptable for use. Additionally, the gaskets on the six CRDMs were replaced with new design graphite

type gaskets.

LER Number 31390021
Plant Arkansas Nuclear Unit #1
Event Date 2/22/1990
Abstract Power level - 000%. On December 22, 1990, maintenance personnel identified a potential Reactor Coolant System leak in the area of a pressurizer upper level instrumentation nozzle. An inspection was conducted which verified the existence of a very small leak at the nozzle. A Notification of Unusual Event was declared at 1011, and the plant was taken to cold shutdown. Subsequent inspection using Nondestructive Examination methods confirmed the existence of a small axial crack in the nozzle inner surface which extended to the annulus between the nozzle and the pressurizer shell and breached the outside diameter (OD) of the nozzle at the toe of the nozzle to vessel weld Based on the location and orientation of the flaw, and industry experience, the most probable root cause was determined to be Pure Water Stress Corrosion Cracking. A temporary repair was completed which consisted of establishing the nozzle pressure boundary at the outside surface of the pressurizer and installing a new nozzle into the penetration from the shell OD. Subsequent evaluations submitted by letters dated December 20, 1991, and January 21, 1992 justified continued operation with the temporary repair in place. This is dependent upon future NDE inspection results consistent with NRC staff safety evaluation dated May 13, 1992.

LER Number 31300003
Plant Arkansas Nuclear Unit #1
Event Date 2/15/2000
Abstract On February 15, 2000, with the plant in cold shutdown conditions for a scheduled outage, a weld in a Reactor Coolant System (RCS) hot leg level instrumentation nozzle was found to have been leaking as indicated by boron buildup. Cracked welds were later found on the other six hot leg level instrumentation nozzles of similar design. One weld crack was subsurface. The root cause was determined to have been using Alloy 182 weld metal exposed to RCS water in a highly restrained weld joint that had not been stress relieved, resulting in Primary Water Stress Corrosion Cracking (PWSCC). Six of the nozzles were replaced in accordance with Section XI of the ASME code using an improved design that included different materials with more resistance to PWSCC. The seventh nozzle was repaired using alternate criteria approved by the NRC because a Section XI repair would have required core offload. This nozzle will receive a Section XI repair during the next refueling outage. The particular nozzle design was used only in these seven locations an is not believed to be installed in any other B&W operating unit.

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LER Number31301002
PlantArkansas Nuclear Unit #1

Event Date	3/24/2001
Abstract	Indication of boric acid crystals were noted in the area of one CRDM nozzle on the RV head during routine visual inspection at the start of a scheduled refueling outage. The other nozzles did not exhibit indications of leakage. NDEs confirmed that a crack in the nozzle had resulted in RCS pressure boundary leakage. The cause of the crack was determined to have been PWSCC. The crack was repaired before the unit was returned to service. The RCS unidentified leak rate before the shutdown did not indicate any significant leakage. A safety assessment concluded that the crack did not pose any risk for catastrophic failure of the nozzle or boric acid damage to the RV head. Routine visual inspections were determined to be adequate to detect future similar cracks before any significant impact on safe operation can occur.

LER Number	36887003
Plant	Arkansas Nuclear Unit #2
Event Date	4/24/1987
Abstract	Power level - 100%. On 4/24/87, an unusual event was declared and a reactor shutdown was commenced due to a suspected reactor coolant system (RCS) pressure boundary leak of approx. 60 drops per minute from the area of the pressurizer vessel lower head. Subsequent investigation revealed that two pressurizer heaters manufactured by Watlow electric company had ruptured resulting in damage to the heater sleeves (which penetrate the vessel head and house the heaters). Damage to one heater sleeve was sufficient to cause RCS pressure boundary leakage which resulted in a small area of boric acid induced corrosion damage to the pressurizer carbon steel base metal. Metallurgical analysis of the damaged components revealed that the heater sheaths had undergone primary water stress corrosion cracking (PWSCC) which allowed water to reach the magnesium oxide (MgO) insulation internal to the heater. Expansion of the MgO due to hydration resulted in the subsequent rupture of the heater sheaths and cracking of the heater sleeve. It has been determined that the manufacturing process of the Watlow heaters induced susceptibility of the sheaths to PWSCC. As a result of this event, all Watlow heaters have been removed from the pressurizer and the two ruptured heater locations have been permanently closed.

LER Number	36800001
Plant	Arkansas Nuclear Unit #2
Event Date	7/30/2000
Abstract	On July 30, 2000, with the plant in cold shutdown conditions for a Steam Generator tube inspection outage, twelve Pressurizer heater sleeves and one RCS hot leg resistance temperature detector nozzle were found to have been leaking. Leakage was indicated by boric acid accumulation.

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The root cause evaluation concluded that the failure mechanism was PWSCC of Alloy 600 material. Inspections were performed at other TCS and Pressurizer locations containing potentially susceptible material. No other leakage was found. Inspections of base material in the area of the leakage revealed no degradation. The leaks were repaired with ASME Code-qualified process. The repairs were qualified for a limited service life until at least the refueling outage scheduled to begin in September 2000.

LER Number 41200003
Plant Beaver Valley Unit #2
Event Date 2/11/2000
Abstract On December 11, 2000, at 0320 hours, the Beaver Valley Power Station Unit No. 2 control room operators received indications of a Primary System leak in the Reactor Containment Building The rate of leakage was noted to b in excess of the TS 3.4.6.2 limit of one gpm for unidentified leakage. A plant shutdown at 2 percent a minute was initiated at 0412 hours. At 0536 hours, the RCS unidentified leak rate was estimated to be between 12 and 20 gpm based on charging/letdown mismatch and an Unusual Event was declared. Plant cooldown and depressurization of the RCS continued and Mode 5 was entered at 1357 hours. The unusual Event was terminated at 1405 hours. This condition is being reported pursuant to 10CFR50.73 (a)(2)(I)(A) as the completion of any nuclear plant shutdown required by the plant's TSs The cause of the RCS leakage into the containment building was an abrupt packing leak on a motor-operated (MOV) drain insolation valve on the RCS. The direct cause of the packing leak was a failure of one of the valve's two stainless steel gland stud eye bolts. The gland stud eye bolts on the RCS primary loop fill and drain valves were replaced with a more stress corrosion resistant material.

LER Number 15598001
Plant Big Rock Point
Event Date 7/14/98
Abstract On March 27, 1998 an unsuccessful attempt was made to discharge the contents of the Liquid Poison System RPS) tank to a group of 55 gallon drums. The tank was supplied with an air source in order to push the liquid poison (sodium pentaborate) out the discharge pipe. Instead of the liquid poison discharging from the LPS tank, air flowed out. A subsequent boroscope inspection of LPS tank internals revealed that the discharge pipe had totally corroded through, and the pipe was severed. The pipe break prevented liquid poison from leaving the tank through the discharge line, compromising the function of the system. Note: this system is not required to be operable for decommissioning. Metallurgical analysis concluded that the pipe protective coating failed due to blistering, allowing the liquid-vapor environment/sodium pentaborate access to the carbon steel discharge pipe. Failure is

postulated to have occurred between 1979 and 1984. Corrective actions included a review of the adequacy of current decommissioning surveillance testing on safety-related SSCs, SSCs important to the safe storage of spent fuel (ISSSF), and SSCs important to the monitoring and control of radiological hazards (IMCRH). Palisades Nuclear Plant, also owned by Consumers Energy, performed a review of their facility with respect to this event.

LER Number 31794004
Plant Calvert Cliffs Unit #1
Event Date 2/21/1994
Abstract Power level - 000%. On February 21, 1994, we discovered higher than anticipated corrosion of three nuts on one of the Incore Instrumentation flanges on the Unit 1 reactor vessel head A subsequent inspection discovered an additional flange with similar degradation. The flanges were known to be leaking slightly since 1993, but we deferred repairs until 1994 because the expected corrosion rate was very low. The excessive corrosion rate was apparently due to the presence of wet boric acid on some of the flange components where we expected only dry boric acid. There were no actual safety consequences, although the potential existed for a significant leak. Corrective action to repair the leaking flanges is complete.

LER Number 31794003
Plant Calvert Cliffs Unit #1
Event Date 3/21/1994
Abstract Power level - 000%. At 1800 hours on February 16, 1994, during removal of insulation from the Unit 1 Reactor Coolant System (RCS) pressurizer (PZR) heater sleeve area, boron deposits were noticed on PZR heater sleeve B-3 indicating leakage from the RCS. At 1700 hours on February 23, 1994, upon completing insulation removal, boron deposits were also identified on PZR heater sleeve FF-1. After discovering the leaks, boroscopic and eddy current testing were performed and heater sleeve FF-1 was examined in the laboratory. The examination revealed a circumferential bulge approximately 0.5 inches long and 0.019 inches high (diametrical) in the area of the boric acid leaks. The most probable cracking mechanism is Primary Water Stress Corrosion Cracking. The bulge area and the axial scoring showed evidence of surface metal smearing and cold work. A search of fabrication records for the PZR turned up evidence that sleeve FF-1 had to be reworked due to the presence of a stuck reamer. The source of stress for the cracking was the bulging and axial scratches associated with the removal of the stuck reamer. Corrective Actions included plugging FF-1 with an Alloy 690 plug welded to the outer diameter of the PZR lower head and examining the remaining Unit 1 PZR heater sleeves.

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LER Number	31889007
Plant	Calvert Cliffs Unit #2
Event Date	5/5/1989
Abstract	Power level - 000%. At 0820 hours May 5, 1989, an in-service inspection of the unit 2 pressurizer discovered evidence of reactor coolant leakage from 28 of the 120 pressurizer vessel heater penetrations and one upper level nozzle. Unit 2 was in a refueling outage (mode 6) at the time of the discovery. At 0430 hours on may 6, 1989, unit 1 was shutdown from 100 percent power (mode 1) to allow inspection of its pressurizer. No signs or evidence of leakage were found on the unit 1 pressurizer heater penetrations or pressure/level penetrations. Additional inspections, including dye penetrant and eddy current tests, of 28 unit 2 and 12 unit 1 heater sleeves were conducted. Three sleeves from unit 2 were destructively examined The cause of leakage was Intergranular stress corrosion cracking of Inconel 600. All cracks were axial and determined to have minimal safety significance. Reaming and repair operations associated with fabricating the unit 2 pressurizer appear to have contributed to the cause. All unit 2 penetrations using j-welds and Inconel 600 were visually inspected. All unit 1 pressurizer penetrations were visually inspected. The unit 2 pressurizer heater sleeves and upper level nozzles were replaced

LER Number	31894003
Plant	Calvert Cliffs Unit #2
Event Date	7/11/1994
Abstract	POWER LEVEL - 100%. On Tuesday, July 11, 1994 at about 1115 hours, a non-isolable Reactor Coolant System pressure boundary leak was discovered at Calvert Cliffs Unit 2. The leak was found to be caused by a 150 degree circumferential crack in a weld in the 22A Safety Injection Tank discharge test connection. In accordance with Technical Specification 3.4.6.2, 'Reactor Coolant System Leakage,' Action A, the Unit commenced a shutdown to hot shutdown (mode 4). The line had been removed and replaced in the spring of 1993. It is suspected that minor changes made at this time resulted in harmonic oscillation causing high cycle fatigue failure. The support for this line was redesigned and similar lines were examined to verify that similar conditions do not exist. The circumstances of this event will be reviewed with Design Engineering personnel. We will evaluate whether additional generic measures to prevent high frequency fatigue failure are appropriate.

LER Number	41389020
Plant	Catawba Unit #1
Event Date	9/21/1989
Abstract	Power level - 100%. On 9/21/89, a preliminary visual inspection of the Catawba units 1 and 2 steel containment vessel (SCV) exterior surfaces was performed between azimuths 0 degrees and 360 degrees at elevation 552 feet + 0 inches. Units 1 and 2 were in mode 1, power

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operation, at 100% and 98% power respectively, when the inspection was conducted The observed corrosion was caused by standing water in the annulus areas. The most significant corrosion occurred in areas where boric acid deposits were also found The root cause of this event is assigned as a design oversight because the slope of the annulus floors was not sufficient to cause flow to the installed floor drains A contributing cause of unanticipated environmental interaction is also assigned because of the chemical reaction between the boric acid and SCV. Design engineering personnel evaluated the extent of corrosion by comparison to the conditions previously observed at McGuire nuclear station. The corrosion observed at the Catawba SCVs bases is not as advanced as at McGuire and does not warrant a separate operability review. The SCV will be repaired and recoated, as applicable, during the next Two refueling outages for each unit. This is a courtesy LER.

LER Number 41401002
Plant Catawba Unit #2
Event Date 9/19/2001
Abstract On September 19, 2001, with Catawba Unit 2 in Mode 5 preparing to enter a refueling outage, a walk down of steam generator 2B lower head bowl drain indicated boron residue buildup on the half inch piping immediately below the SG. The origin of the residue appeared to be adjacent to the bowl drain nozzle at the partial penetration weld between the nozzle coupling and the outer channel head surface. The pressure boundary leakage path was suspected to be the nozzle coupling to vessel weld. This event was reported to the NRC at 2212 on September 19, 2001 as an eight hour non-emergency phone call pursuant to 10 CFR 50.72 (b)(3)(ii)(A). The root cause of the SG 2B bowl drain leak is PWSCC of Alloy 600 material.. The 2B SG bowl drain leak was repaired and tested satisfactorily. The remaining three SGs on Unit 2 were visually inspected and liquid penetrant tests were performed. No similar leaks were detected Long term corrective actions include evaluating SG drain line enhancements to preclude leakage and development of a program to address Alloy 600 issues This issue is not applicable to Unit 1 because the SGs are of a different design that does not have a similar drain line.

LER Number 31598027
Plant Cook Unit #1
Event Date 5/5/1998
Abstract On May 5, 1998, inspection results identified varying amounts of construction-related debris and boric acid deposits in the Unit 1 Containment Spray header and RHR spray header and nozzles. The debris was assumed to have existed while Unit 1 was in operation and could have potentially resulted in the CTS and the RHR system not being able to perform their design function. On August 7, 1998, limited inspections of the Unit 2 CTS and RHR system spray headers and nozzles also identified varying amount of construction-related debris. On

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March 1, 2000, LER 315/98-027-01 was submitted to the NRC. The cause for the construction-related debris is inadequate cleanliness inspections performed during initial plant construction. The most probable cause for the boric acid deposits/blockage in the Unit 1 RHR spray piping is inadequate inspection of RHR system piping after a 1979 inadvertent spray actuation.

LER Number 30201004
Plant Crystal River Unit #3
Event Date 10/1/2001
Abstract At 1300, on October 1, 2001, Florida Power Corporation's Crystal River Unit 3 was in Mode 5 at o percent rated thermal power. While performing a visual inspection of the reactor vessel head, FPC personnel identified on potential leaking CRDM nozzle. The RV head inspection was performed to satisfy a commitment made by FPC in response to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles " At approximately 1748, on October 8, 2001, CR-3 was in Mode 6 at 0 percent rated thermal power. UT examination of RV head nozzle #32 identified the leakage path as two axially oriented cracks that were through-wall An 8-hour notification was made to the NRC in accordance with 10CFR50.72(b)(3)(ii)(A) due to confirmation of Reactor Coolant Pressure Boundary leakage while at power. The cracks were cause by PWSCC. Eight additional CRDM nozzles were examined using UT. No evidence of cracking was observed in the additional CRDM nozzles inspected.

LER Number 34698009
Plant Davis-Besse Unit #1
Event Date 9/9/98
Abstract On September 18, 1998, at 1610 hours with the plant in Mode 1 at 100 percent power, a Potential Condition Adverse to Quality Report (PCAQR) documented that an engineering evaluation determined that Reactor Coolant Pressurizer Spray Valve (RC- 2), with two of the eight body to bonnet nuts missing, was not functional for design loads At the time the engineering evaluation was completed, replacement nuts had been installed. The Nuclear Regulatory Commission (NRC) was notified of this condition at 1658 hours on September 18, 1998, via the Emergency Notification System, in accordance with 10CFR50.72(b)(1)(ii)(B). This condition was reported in accordance with 50.73(a)(2)(ii)(B), as a condition outside of the design basis. The most probable cause for the two missing nuts on RC-2 is that a packing leak allowed boric acid corrosion of two carbon steel nuts that were inadvertently installed on RC-2, due to less than adequate material separation work practices during previous maintenance activities. These nuts were subsequently replaced on September 9, 1998, and September 10, 1998, on-line leak sealing activities were conducted on September 10, 1998, to stop the boric acid leak at RC-2. on October 16, 1998, it was discovered that the second nut, installed on September 10, 1998, was not installed properly

and was therefore, not a fully functional fastener. At this same time, it was discovered that an additional nut was degraded. On October 17, 1998, all eight RC-2 body to bonnet nuts were replaced with stainless steel nuts. Subsequently, a finite element analysis was performed by the valve vendor to determine if the valve would have functioned in the one, two, or three missing nut configuration. The results of the analysis concluded that the valve would have functioned in each of the configurations, with minor degradation, to maintain the integrity of the reactor coolant system pressure boundary under design loading conditions.

LER Number 34602002
Plant Davis-Besse Unit #1
Event Date 2/27/02
Abstract On February 27, 2002, at 1330 hours, ultrasonic (UT) examination of the Control Rod Drive Mechanism (CRDM) nozzles revealed axial indications in the J-groove weld and Alloy 600 nozzle resulting in pressure boundary leakage for CRDM nozzle #3. On March 5, 2002, a follow-up notification was made to report completion of the UT examinations and through pressure boundary axial indications in he Alloy 600 nozzles at CRDM nozzles #1 and #2. The apparent cause of the axial flaws resulting in pressure boundary leakage was determined to be Primary Water Stress Corrosion Cracking (PWSCC). The root cause of the RPV head condition is boric acid corrosion resulting from moisture introduced due to PWSCC cracking of CRDM nozzle #3. Industry and NRC assessments have previously concluded that axial flaws do not present an immediate safety concern. Therefore, the discovery of these flaws alone has minimal safety significance. The as-found condition of the RPV head was assessed and would have functioned to maintain the RPV head structural integrity during anticipated operational occurrences and postulated accidents. A safety significance assessment of the degraded RPV head was submitted to the NRC on April 8, 2002 (DBNPS letter Serial Number 1-1268). This submittal provided a detailed assessment for the degradation of the RPV head. This evaluation determined that in its degraded condition, structural integrity would have been maintained, based on an average clad thickness of 0.297 inches over a conservative area of degradation, to approximately 5600 pounds per square inch. Evaluation of the minimum clad thickness of 0.24 inches over the conservative area of degradation resulted in structural integrity being maintained to approximately 4600 pounds per square inch. Thus, the as-found head would have functioned to maintain structural integrity during anticipated operational occurrences and postulated accidents. A deterministic safety assessment was performed and concluded that in the unlikely event of RPV head failure considering the as-found degraded condition: a) adequate core cooling could have been established and maintained for the long term, b) the reactor could have been placed and maintained in a safe shutdown condition, and c) the integrity of the containment would not have ben compromised. In addition, a

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probabilistic safety assessment concluded, per Regulatory Guide 1.174 guidelines, that there was a small increase in core damage frequency and a very small increase in large early release frequency.

LER Number 27588004
Plant Diablo Canyon Unit #1
Event Date 2/25/1988
Abstract Power level - 068%. This voluntary LER is being submitted for information purposes only as described in item 19, of supplement number 1, to NUREG-1022. On February 25, 1988, with the unit in mode 1 (power operation), an unexplained increase in containment airborne radiation was observed. On March 12, 1988, following plant shutdown, examination of the reactor vessel head duct work disclosed a leak in the canopy seal weld of the control rod drive mechanism (CRDM) head adapter plug at spare location I-5. Subsequent visual inspections revealed additional canopy seal weld leaks at spare locations j-5, I-9, and I-11. From April 8 through April 21, 1988, the identified head adapters were removed and replaced with caps welded in place. All repairs were determined to be satisfactory and constituted a permanent repair for these locations. The metallurgical examinations performed on the head adapters removed from locations J-5, I-9, and I-11, indicated that the leaks were initiated at the inside diameter of the canopy and were caused by transgranular stress corrosion cracking STPR-8A, 'Reactor Coolant System Operational Pressure Leak Test', was revised to include a CRDM inspection.

LER Number 27590010
Plant Diablo Canyon Unit #1
Event Date 7/26/1990
Abstract Power level - 100%. On July 31, 1990, it was determined that unit 1 could have potentially operated outside the control room habitability design basis for a post-LOCA recirculation condition due to leakage through a crack in the unit 1 positive displacement charging pump (PDP) suction piping elbow. A one hour non-emergency report was made to the NRC at 1245 PDT on July 31, 1990, in accordance with 10 CFR 50.72(b)(ii)(b). The crack, which was discovered on July 26, 1990, was observed to be weeping a small amount of water which evaporated immediately. As a compensatory measure, emergency procedure E-1.3, 'Transfer to Cold Leg Recirculation', was revised on July 28, 1990 to verify that the auxiliary building safeguards air filtration system is in the 'safeguards only' mode during post-LOCA conditions. In this mode, leakage from the PDP room would be filtered prior to its release. The cause of the crack is considered to be vibration induced high cycle fatigue. The crack was repaired by an ASME Section XI weld repair. Vibration data will be collected and evaluated. Based on the results of the evaluation, an action plan will be developed to address any recommended modifications.

LER Number	32387023
Plant	Diablo Canyon Unit #2
Event Date	10/9/1987
Abstract	Power Level - 100%. This voluntary Licensee Event Report is submitted for information only as described in Item 19 of Supplement 1 to NUREG-1022. This LER describes leaks in Unit 2 accumulator nozzles resulting from intergranular stress corrosion cracking (IGSCC) and a weld defect. Cracking in both Units 1 and 2 accumulator nozzles and in the cladding of two of the Unit 2 accumulator tanks was identified during planned refueling outage inspections as a result of using inspection techniques of higher sensitivity than those previously used. The root cause of the flaws identified was IGSCC caused by a combination of factors during manufacture of the accumulators and a suitable incubation time. All nozzles that had unacceptable indications were weld-repaired or replaced with nozzles made of Type 304L stainless steel during the fifth refueling outage of both Units 1 and 2. The cracking in the Unit 2 accumulators cladding was evaluated in WCAP-13711 and left 'as-is' with NRC consent since there is no mechanism present to drive the cracks into the base metal (Reference: NRC letters to PG&E dated April 22, 1993, and September 2, 1993). Attachments 1 and 2 provide a complete repair history of Unit 1 and 2 accumulator nozzles.

LER Number	28590028
Plant	Ft. Calhoun Unit #1
Event Date	12/14/1990
Abstract	Power level - 002%. On December 14, 1990, an investigation of unknown reactor coolant system (RCS) leakage identified the source as installed spare control element drive mechanism (CEDM) housing number 9. Subsequent removal and inspection identified two axial cracks in an inside diameter weld overlay region approximately two feet from the bottom flange of the housing. Similar installed spare CEDM housing number 13 was also removed and inspected, revealing two similar cracks in the weld overlay region. The cause of this event was lack of venting, which created conditions conducive to transgranular stress corrosion cracking (TGSCC) in the spare housings. This report is submitted voluntarily due to potential NRC and industry interest. Blank flanges were installed in place of CEDM housings 9 and 13. A procedure change has been implemented to assure complete venting of two other similar housings. Other appropriate CEDM housings have been examined with no cracks found. An enhanced RCS leakage monitoring program has been implemented

LER Number	28592018
Plant	Ft. Calhoun Unit #1
Event Date	3/20/1992
Abstract	Power level - 000%. On March 20, 1992, with the plant in a refueling outage, the removal of insulation and heat tracing from the boric acid system during implementation of a modification revealed severe corrosion of the carbon steel fasteners on the boric acid pump flanges and piping supports. The corrosion was extensive enough to have led to a possible failure of the fasteners during a seismic event. This event is being reported pursuant to 10CFR50 72(b)(2)(I). This report is being submitted pursuant to 10CFR50.73(a)(2)(ii) and 10CFR50.73(a)(2)(vii). The root cause of this event was the original design of the flange connections did not anticipate corrosion problems due to boric acid leakage at the system flange connections. The carbon steel fasteners were covered with glued heat tracing and asbestos insulation, thus, sealing the fasteners in a potentially high corrosive environment. Based on the configuration of the charging header and the availability of operator actions to mitigate the consequences of a complete loss of boric acid storage tank (BAST) inventory, the safety significance of the degraded flanges was minimal. The postulated loss of a BAST would not significantly affect plant safety. As corrective action, the carbon steel fasteners were replaced.

LER Number	21396019
Plant	Haddam Neck Unit #1
Event Date	8/31/1996
Abstract	On August 31, 1996, at 1050 hours, with the plant in Mode 5 (cold shutdown), a plant operator during a routine inspection identified a pinhole leak in the body of an eight inch inlet isolation valve (RH-V-791A) to the 'A' residual heat removal (RHR) heat exchanger. A small buildup of boric acid on the valve body was noted and when it was wiped off a small amount of water (<0.1 ml/min) weeped from the valve. In accordance with ASME Code Section XI guidance the valve was declared inoperable. At the time of this event the plant had been shut down since July 22, 1996 (LER 96-013-00) and was in a refueling and maintenance outage. The RHR system was Inservice at the time of this event. Initial corrective action consisted of placing the 'B' RHR heat exchanger in service and isolating the 'A' RHR heat exchanger. The leak was in the neck area of the valve above the disc, the weeping stopped when the subject valve was closed. A radiographic examination of the valve was performed and no significant structural defects were identified. The status of residual heat removal valve RH-V-791A was dispositioned as operable but degraded and an ASME relief request was approved by the NRC. The reactor core was offloaded. Long term corrective action was to repair or replace the valve however these actions are no longer required due to the Haddam Neck plant being in a permanently defueled state.

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LER Number	30995013
Plant	Maine Yankee Unit #1
Event Date	0/16/1995
Abstract	Power level - 000%. This is a voluntary LER. During the events described in this LER, Maine Yankee was steady state in a Refueling Shutdown condition with fuel off loaded to the Spent Fuel Pool. On April 26, 1995, the bonnet on High Pressure Safety Injection Loop 3 Stop valve HSI-36 dropped down into the valve body while the valve was being closed. The bonnet dropped because all eight of the bonnet retention cap screws had failed due to hydrogen embrittlement. On October 16, 1995, during an inspection of High Pressure Safety Injection Loop 2 Stop valve HSI-26, seven of eight bonnet retention cap screws parted during attempts to remove them due to boric acid corrosion. HSI-26 and 36 are a 10 inch gate valve with a pressure seal bonnet design. As a result of this design the bonnet retention cap screws are not pressure retaining components, their only function being to hold the bonnet in place in the absence of system pressure. The immediate corrective action was to seal weld the bonnet for HSI-26 and replace the bonnet screws of HSI 36. Corrective actions taken included identification and review of other pressure seal valves for similar susceptibility, and conducting a causal factors analysis of this condition in an effort to identify other areas where additional corrective action may be warranted.

LER Number	36989020
Plant	McGuire Unit #1
Event Date	7/27/1989
Abstract	Power level - 100%. On 7/27/89, design engineering personnel discovered abnormal degradation of the unit 2 steel containment vessel (SCV) because of corrosion. This discovery was made while performing a preliminary inspection of the SCV prior to integrated leak rate testing. The corrosion was caused by standing water in the annulus area. The most significant corrosion occurred in areas where boric acid deposits were also found. The boric acid deposits resulted from leaking instrumentation connections. This event is assigned a cause of truly unknown because the failure of the drain system to prevent standing water in the annulus area could not be determined. Assigned because the junction between the SCV and concrete floor was not sealed. A second contributing cause of unanticipated environmental interaction is also assigned because of chemical reaction between the boric acid and SCV. Unit 1 was in mode 1, power operation, at 100% power and unit 2 was in no mode, no fuel in the core, when this event was discovered. Unit 2 had previously operated in mode 1 at 100% power with these conditions existing. Design engineering personnel performed a preliminary inspection of unit 1 and detected similar degradation. Design engineering personnel evaluated the extent of degradation and provided an operability determination.

LER Number	33695023
Plant	Millstone Unit #2
Event Date	5/16/1995
Abstract	Power level - 000%. On May 16, 1995, at 1100 hours, with the plant In Mode 6, lincar indications were found (by liquid penetrant testing, LP) on two separate tee fittings in the Boric Acid section of the Chemical and Volume Control System (CVCS). The LP examinations were being performed as part of several piping configuration changes. The indications were on lines 2-HCB-15 and 16, the 'B' Boric Acid Pump Recirculation header. The tees were removed and examined metallurgically. The exams revealed OD initiated stress corrosion cracking (SCC). Based on this finding and industry problems with SCC on heat traced stainless steel piping, an expanded piping examination program was initiated. The expanded examination program revealed additional indications on other fittings and pipe, all of which had previously been heat traced and insulated and had been subjected to periodic boric acid leaks over the years from relief valves and other valves in the vicinity. Several hanger supports were also found degraded once all the insulation was removed. No through wall leaks were found at any location. The root cause of the SCC on fittings and the hanger degradation is periodic boric acid leaks from relief and other valves which over the years collected on and soaked onto the pipe and Insulation, and the lack of timely resolution of this condition. Upon evaporation on the heat traced piping, halogen contaminants such as chlorides and fluorides concentrated in specific areas on the piping and fittings. These contaminants provided the mechanism to promote SCC. Repairs were initiated including replacement of all degraded fittings and pipe within the Boric Acid System. This event is being reported pursuant to the requirements of 10CFR50.73(a)(2)(v)(A), any event or condition that alone could have prevented the fulfillment of the safety function of structures or system that are needed to shutdown the reactor and maintain it in a safe condition.

LER Number	33602001
Plant	Millstone Unit #2
Event Date	2/19/2002
Abstract	On February 19, 2002, with the plant in Mode 5 (Cold Shutdown), a visual inspection of Millstone Unit No. 2 pressurizer heater penetrations and pressurizer instrument nozzle penetrations was being performed. Two heater sleeve penetrations were found to show indications of minor leakage as evidenced by boron precipitation build up on the outside of the penetrations. The cause of this event was a through wall crack in two of the pressurizer heater sleeves. This allowed primary coolant into the annulus between the pressurizer lower head and the heater sleeve and therefore was a breach of he reactor coolant pressure boundary. The leaking heater sleeves have been repaired by the use of Mechanical Nozzle Seal Assembly (MNSA) clamps.

LER Number	42389031
Plant	Millstone Unit #3
Event Date	11/28/1989
Abstract	Power level - 100%. On November 28, 1989, at 1515 hours, at 100% power (Mode 1), a loose nozzle ring set screw on the 'C' pressurizer safety valve was found with steam discharging from the set screw location. The nozzle ring, which is held in place by the set screw, is essential in assuring the valve pops fully open. Since a proper nozzle ring setting was no longer assured, the safety valve was declared inoperable. With only two (2) of three (3) pressurizer safeties operable, the plant was in a condition prohibited by the Technical Specifications. The plant was then placed in Cold Shutdown (Mode 5) at 1450 hours on November 29, 1989, for valve inspection. An inspection of the valve revealed that the set screw threads were corroded or steam cut to a point where the set screw backed completely out of its location. The root cause was the use of a carbon steel rather than a stainless steel set screw. Carbon steel is susceptible to corrosion/erosion in a hot boric acid and steam environment. The valve was replaced with a recently calibrated spare safety valve, and the plant was returned to 100% power. After installing a stainless steel nozzle ring set screw in the faulty valve, it was recalibrated and made available as a spare.

LER Number	42394012
Plant	Millstone Unit #3
Event Date	9/9/1994
Abstract	Power level - 000%. On September 9,1994, with the plant in Mode 4, at 0% power, a leak was discovered in 3/4-inch socket weld on a 'C' Reactor Coolant System (RCS) Loop Flow Instrumentation line. The weld was removed for analysis during which liquid penetrant testing identified a circumferential crack approximately, 5/8-inch long. Initial metallurgical analysis indicated that the root cause of the socket weld failure was most probably a weld defect, believed to result from a lack of fusion in the weld root pass. The defect propagated to the weld surface. This condition is being reported in accordance with 10CFR50.73(a)(2) (I)(B), as an operation or condition prohibited by Technical Specifications. Technical Specification 3.4.6.2 requires 'No Pressure Boundary Leakage' (i.e., nonisolable fault). Although this incident involved a reactor coolant leak, it had low safety significance. Leakage was collected within the containment drain system. The port to the RCS loop is a 3/4-inch diameter restriction, which would have minimized leakage from the RCS in the event of total failure. The normal makeup system has sufficient capacity to maintain pressurizer level and compensate for a failure of this line. A review of similar events identified a previous RCS socket weld failure, that was discovered in cold shutdown on May 16, 1992. This LER also documents that historical condition which was not previously reported. For the same reasons as identified above, that incident had low safety significance.

LER Number	42395020
Plant	Millstone Unit #3
Event Date	12/2/1995
Abstract	Power level - 000%. On December 2, 1995, with the plant in Mode 5, Cold Shutdown, a leak was discovered on the valve stem leak-off pipe for the Residual Heat Removal System supply from a Reactor Coolant System loop inboard isolation valve (3RHS*MV8701C). This pipe had been modified to vent the valve bonnet to the RCS, to prevent pressure locking / thermal binding of the valve disc. This condition is conservatively being reported in accordance with 10CFR50.73(a)(2)(i)(B) as a condition prohibited by Technical Specifications. Technical Specification 3.4.6.2 requires 'no pressure boundary leakage' in Modes 1-4. This report is being made due to the possibility of having unisolable leakage past the disc of 3RHS*MV8701C, even with the valve in the closed position during Modes 1, 2, and 3. Some leakage is possible since the disc is a flex wedge design, which could allow pressure upstream of the valve to leak past the upstream seat of the disc and into the bonnet chamber. This pressure then assists in sealing the downstream seat of the disc. (See Sketch 1 for leakage path through the valve). In Mode 4, one train of RHR is required for plant cooldown, which could require opening this valve. 3RHS*MV8701 C could then be placed on its backseat to isolate the bonnet, and the downstream isolation valve(s) 3RCS*V969, V2002, V2003 could be closed to isolate the leak. (See Sketch 2 for piping layout). However, if the opposite train of RHR is being used to cool the RCS, 3RHS*MV8701C would remain closed and the leak path through the valve still exists. An initial inspection indicated a crack near the toe of the fillet weld between the pipe and the valve body. The leaking section of pipe was removed for further evaluation which resulted in the discovery of six linear indications at a 45-degree angle to the pipe. (See Sketch 3 for inspection results). None of the indications were in the weld material, all were located in the pipe. Although this incident involved reactor coolant leakage, it had low safety significance. The pipe connection to the RCS has a 0.375-inch diameter orifice to limit RCS leakage. Also, the hole in the valve bonnet between the stuffing box and the stem leak-off pipe is only 0.25-inch in diameter. These restrictions limit potential leakage to within the capacity of the normal makeup system.
LER Number	33901003
Plant	North Anna Unit #2
Event Date	11/13/2001
Abstract	On October 18, 2001, NA 2 was shutdown to perform a qualified, visual bare head inspection of the reactor vessel head penetrations for evidence of leakage as required by NRC Bulletin 2001-01. On November 13, 2001, with Unit 2 in Mode 6, an apparent through-wall leak on penetration number 63 was identified based on the presence of boric acid deposited at the based of the penetration and the results of a subsequent liquid

penetrant examination of the associated J-groove weld area A non-emergency 8 hour notification was made to the NRC, at 0859 hours, on November 13, 2001, in accordance with 10CFR50 72(b)(3)(ii)(A). The cause of the event was hot-short cracking, which occurred during original fabrication of the reactor vessel head. Repairs to the welds were performed in accordance with NRC verbally approved relief requests to eliminate any leakage path. An evaluation also determined that a complete lack of fusion in the zone between the weld and the head would not result in rod ejection accident because the weld to the tube would prevent it.

LER Number	26900006
Plant	Oconee Unit #1
Event Date	12/4/2000
Abstract	On November 25, 2000, at 0300 hours, with Oconee Unit 1 in Mode 5 and preparing to enter refueling outage 19, a periodic visual inspection of the top surface of the Reactor Pressure Vessel head revealed small amounts of boric acid deposited on the VH surface. The deposits appeared to be located at the base of 5 (of the 8) unused thermocouple and the #21 CRDM nozzles at points where they penetrate the RPV head surface. A more detailed video inspection, performed on December 1, 2000, confirmed the presence of the boric acid around the suspect nozzles. On December 4, 2000, an eddy current test was performed on the inside surface of the 8 T/C nozzles and revealed axial crack-like indication on the ID of the nozzles in the vicinity of the partial penetration weld (on the underside of the RPV head). On December 9, 2000, dye penetrant testing on CRDM #21 identified two very small pin hole indications, After lightly grinding and performing another PT, a .75 inch hole indication running at a slightly sewed angle across the fillet weld was identified. Following completion of the root cause analyses, PWSCC was determined to be the primary failure mechanism of both the T/C nozzles, and CRDM weld cracks Prior to restart, the #21 CRDM weld was repaired and the 8 T/C nozzles removed and their resultant head penetrations permanently plugged.

LER Number	27097001
Plant	Oconee Unit #2
Event Date	4/21/1997
Abstract	On April 21, 1997, Unit 2 was at 100% Full Power(FP). At 2245 hours, Operators noted indications of a 2.5 gpm Reactor Coolant System (RCS) leak. The source could not be determined, so at 0352 hours on April 22, power reduction began. At 20%FP Operators could not identify the leak as isolable, so the decision was made to go to cold shutdown. At 1448 hours, the reactor was tripped by a planned test. At 1500 hours, a NOUE was declared when the leak exceeded 10 gpm. The NOUE was terminated at 2032 hours after the leak reduced below 10 gpm. The leak was found to be a crack at the safe end to pipe weld on the High Pressure Injection to RCS cold leg nozzle near Reactor Coolant Pump

2A1. The safe end and pipe were found to be cracked internally and the thermal sleeve was found to be loose and damaged The failures were caused by thermal cycling fatigue. The root causes were determined to be failure to implement an effective HPI nozzle inspection program based on available industry recommendations and failure to effectively evaluate known problems and implement appropriate corrective actions Corrective actions include repair of the nozzle components and establishing an effective program to inspect and support nozzles. Evaluation shows that the HPI line still had a factor of safety greater than 2 under design basis event loads Prompt shutdown prevented the development of an unsafe condition

LER Number 27001002
Plant Oconee Unit #2
Event Date 4/28/2001
Abstract At approximately 1500 hours on April 28, 2001, a visual inspection of the top surface of the Oconee Nuclear Sation Unit 2 RPV head found evidence of small accumulations of boric acid deposited at the base of CRDMs nos. 4, 6, 18, and 30. The RPV head inspection was performed as part of a normal surveillance during a planned refueling outage. Subsequent surface PT inspections of the weld area and nozzle outside diameter identified several axial cracks on four CRDM nozzles that initiated near the toe of the fillet well and had propagated radially into the nozzle material as well as axially along the OD surface. The cracks are believed to be the leakage pathway for the boric acid deposits on the Unit 2 RPV. Eddy current (EC) emanation revealed two shallow axial flaws on CRDM nozzle 16 and craze cracking on all four CRDM ID surfaces. Supplemental ultrasonic test (UT) examinations were used to size the EC indications and determine the through-wall extent of other indiction that EC could not resolve. The UT results confirmed the existence of some crack (none through wall) predominately axial with one short OD initiated circumferential crack on CRDM nozzle 18. The most probable root cause of the Alloy 600 CRDM nozzle leads is PWSCC based on comparison of the PT, EC, and UT results form the four ONS-2 CRDM nozzles and the documented NDE and metallurgical result of the previous ONS-1 and ONS-3 CRDM analyses, material samples and repairs.

LER Number 28791008
Plant Oconee Unit #3
Event Date11/23/1991
Abstract Power level - 100%. On November 23, 1991, Oconee unit 3 was operating at 100% full power (FP) when the control room operators (CROS) received several alarms at 0141 hours which indicated failed instruments inside the reactor building (RB). At 0143 hours, the CROS observed symptoms of excessive reactor coolant system (RCS) leakage and began assessing the leak rate. At 0203 hours, they started a rapid controlled shutdown. At 0214 hours, the shift supervisor concluded that leakage was approximately 60 to 70 gpm, and declared an alert. At 0327

hours, the unit tripped from 33% FP due to a control oscillation while the CROS were attempting to secure a feedwater pump At 0641 hours, an additional unanticipated reactor protective system actuation occurred due to operator error. At 1720 hours the unit reached cold shutdown and the alert was terminated. The leak was determined to be a failed fitting on an instrument line at the top of a steam generator. A total of approximately 87,000 gallons of RCS leakage was confined within the RB. The Instrument line was replaced, and additional fittings inspected. The root causes are management deficiency and equipment failure.

LER Number	28701001
Plant	Oconee Unit #3
Event Date	2/18/2001
Abstract	At 2100 hours on February 18, 2001, a visual inspection of the top surface of the Oconee Nuclear Station Unit 3 (ONS Unit 3) Reactor Pressure Vessel (RPV) head found evidence of small accumulations of boric acid deposited at the base of several control rod drive mechanism (CRDMs). This RPV head inspection was performed as part of a normal surveillance during a planned maintenance outage. The boric acid deposits were identified around nine (Nos. 3, 7, 11, 23, 28, 34, 50, 56, and 63) of the sixty-nine total CRDM nozzles. The amount of boric acid around each of the CRDM nozzles was estimated to be no more than a few cubic inches but ultimately signified that reactor coolant system pressure boundary leakage had occurred. Subsequent non-destructive testing was performed on a total of eighteen CRDMs, in order to effectively evaluate, characterize the leak mechanism, and determine extent of the condition. The apparent root cause of the nine CRDM nozzle leaks is primary water stress corrosion cracking (PWSCC). The nine leaking CRDMs have been repaired. This event is considered to have minimal safety significance with respect to the health and safety of the public.

LER Number	28701003
Plant	Oconee Unit #3
Event Date	11/12/2001
Abstract	On November 12, 2001, a visual inspection of the top surface of the Oconee Nuclear Station Unit 3 reactor vessel head found evidence of small accumulations of boric acid deposited at the based of several CRDM nozzles. This RV head inspection was performed as part of a planned surveillance activity during the In-of-cycle 19 refueling outage. Following the visual inspection, NDE of the suspect nozzles revealed that seven (Nos. 2, 10, 26, 31, 39, 49, and 51) of the 69 total nozzles required repair. Five of the 7 nozzles were confirmed to have leakage pathway to the top of the RV head. The amount of boric acid around the five leaking nozzles was estimated to be no more than a few cubic inches. After confirming that notification was made at 0335 hours on November 12, 2001. The apparent root cause of the CRDM nozzle leaks is PWSCC. The seven CRDMs were repaired and the remaining 43 nozzles that had

neither been previously examined nor reported, were inspect using an ultrasonic circumferential blade and probe prior to exiting the refueling outage.

LER Number	25593011
Plant	Palisades Unit #1
Event Date	10/9/1993
Abstract	Power level - 000%. On October 9, 1993, at approximately 0900 hours, the plant was in cold shutdown and beginning heat up. Inspection of the pressurizer upper temperature nozzle penetration (TE-0101) found it to be leaking. Subsequent inspection of the lower temperature nozzle penetration (TE-0102) found it to be leaking also. The root cause was determined to be primary water stress corrosion cracking of the Inconel 600 nozzle material. Other similar penetrations in the PCS were inspected and none showed evidence of any past or present leakage. The two leaking pressurizer temperature nozzle penetrations were repaired. A comprehensive Inconel 600 inspection and maintenance program will be developed for the Palisades plant.

LER Number	25599004
Plant	Palisades Unit #1
Event Date	11/2/1999
Abstract	On October 16, 1999, following shutdown of the reactor for the 1999 refueling outage, inspection of reactor head components revealed the presence of moisture and/or boric acid deposits on the exterior surfaces of three CRDM seal housings. The CRDM seal housing assemblies comprise a portion of the ASME Class 1 primary coolant system pressure boundary. The affected seal housing s were removed when plant conditions permitted, and on November 2, 1999, two of the three were determined to have small through-wall cracks. All 45 seal housings were ultimately removed from the head and inspected utilizing visual, PT, and EC examination techniques. The inspections revealed that 30 of the 45 seal housing assemblies contained small circumferential cracks. Three seal housing tubes also contained small axial cracks Examination of spare housing showed similar crack indications. The cracking has been determined to be transgranular stress corrosion cracking , probably resulting from inadequate post-weld heat treatment which left residual stresses of sufficient magnitude to support cracking. 45 seal housing assemblies were repaired as necessary for reuse during the next operating cycle.

LER Number	25501002
Plant	Palisades Unit #1
Event Date	3/31/2001
Abstract	On March 31, 2001, during an inspection of the reactor head area following shutdown for a refueling outage, a boric acid deposit and a small amount of water were found on the CRDM seal housing for CRD-22. The CRD seal housing assemblies comprise a portion of the

ASME Class 1 primary coolant system pressure boundary. The housing was removed from the RV head when conditions permitted. Subsequent investigation confirmed the presence of reactor coolant system through-wall leakage through a small (approximately 0.70 inches long) circumferentially oriented crack on the inside diameter of the seal tube. The housing also contained a confirmed axial crack (approx. 0.05 inches long) that was not through-wall. All 44 remaining seal housings were removed for examination. 100% of the seal tubes were inspected using visual and/or fluorescent dye penetrant NDE methods. In addition to CRD-22, the inspections confirmed a circumferentially oriented crack (approx. 0.15 inches long) in CRD-8 that was not through-wall. No other crack-like indications were confirmed A total of 13 seal housings were not returned to service due to NDE indications, confirmed cracks (in CRD-22 and CRD-8), or mechanical seal performance deficiencies. Thirteen new Inconel (Alloy 600) housings were installed on the RV head The cracking confirmed in CRD-22 and CRD-8 has been determined to be transgranular stress corrosion cracking, most likely resulting from inadequate post-weld heat treatment which left residual stresses of sufficient magnitude to support cracking

LER Number	52899006
Plant	Palo Verde Unit #1
Event Date	10/2/1999
Abstract	On October 2,1999, at approximately 0300 mountain standard time, Unit I was in Mode 3, Hot Standby, cooling down for a refueling Outage when engineering personnel, who were performing a routine boric acid walkdown, discovered a small accumulation of boric acid residue on a reactor coolant system loop 2 hot leg instrument nozzle. The boric acid had accumulated on the exterior of the hot leg piping around the outer perimeter of the instrument nozzle. The nozzle was visually inspected during the last refueling Outage in March of 1998 and no leakage was identified at that time. Visual Inspections of other Alloy 600 hot leg nozzles have not identified other degraded components. The nozzle has been repaired and testing will be completed during startup (Mode 3) at normal operating pressure and temperature. The remaining Alloy 600 hot leg nozzles in all three units are scheduled to be replaced during future Outages. No previous similar events have been reported pursuant to 1OCFR5O.73 in the past three years.

LER Number	52801001
Plant	Palo Verde Unit #1
Event Date	3/31/2001
Abstract	On March 31, 2001, with Unit 1 operating in Mode 4, hot shutdown, and cooling down to Mode 5, cold shutdown, for a refueling outage engineering personnel discovered boric acid on a reactor coolant system hot let Instrument nozzle. The cause of the boric acid accumulation was PWSCC of alloy 600 Inconel material in the Instrument nozzle. The amount of boric acid found demonstrates the crack was small and the

leakage rate low. The nozzle was visually inspected during the last refueling outage in 1999 with no leakage Identified. Visual inspections of other alloy 600 hot leg nozzles did not identify degraded components. As corrective action the nozzle was modified during the refueling outage and prior to the Unit entering Mode 4. In addition, the current Palo Verde Alloy 600 strategy is to modify all alloy 600 hot leg nozzles during future outages.

LER Number	52900004
Plant	Palo Verde Unit #2
Event Date	10/4/2000
Abstract	On October 4, 2000,. At approximately 2300 mountain standard time, Unit 2 was in Mode 4, hot shutdown, cooling down for a refueling outage when engineering personnel discovered a small accumulation of boric acid residue on a reactor coolant system pressurizer heater sleeve. The condition was identified during a routine boric acid walkdown of the reactor coolant system hot legs. Subsequent eddy current testing confirmed a liner indication in the sleeve. Visual inspections of other RCS Alloy 600 hot leg components did to identify other degraded components. An ENS notification was made on October 5, 1248 MST to report the condition. The sleeve has been repaired and testing will be completed during startup (Mode 3) at normal operating pressure and temperature.

LER Number	26690008
Plant	Point Beach Unit #1
Event Date	7/20/1990
Abstract	Power level - 100%. Point beach nuclear plant unit 1 was shut down from 100 percent power on July 20, 1990, at 0839 CDT to repair leaks in the reactor coolant system with an average total leakage of approximately 0.27 gallons per minute. Reactor coolant was leaking through a canopy seal weld on control rod drive mechanism I-3 and the upstream weld on B steam generator channel head drain line isolation valve 1RC-526B. Both leaks were repaired by welding and the plant was brought on line July 29, 1990, at 0556 CDT.

LER Number	26699012
Plant	Point Beach Unit #1
Event Date	11/4/1999
Abstract	This report discusses the discovery of an approximately 1/64 inch through-wall defect or flaw on the upstream weld for valve 1RC-526A, the isolation valve for the Unit 1 ~AU steam generator channel head drain. This indication was discovered while conducting an informational liquid dye penetrant examination of that weld due to the visual identification of boric acid crystals on the weld. The unit was shutdown at the time of this discovery. A four hour non-emergency event notification was made to the NRC at 0307 CST on November 4, 1999, in accordance with 10 CFR50.72(b)(2)(I) for an event discovered while the plant was shutdown

that, had it been discovered while the reactor was operating, would have resulted in the principal safety barriers being seriously degraded The weld has been replaced

LER Number	None
Plant	Salem Unit #2
Event Date	8/7/1987
Abstract	On August 7, 1987, after an unplanned shutdown, Salem Unit 2 was brought to a cold shutdown condition. Inspection teams entered the containment building to look for reactor coolant leaks that would account for the increased radioactivity in containment air that was noted before the shutdown. The team assigned to the reactor head area found boric acid crystals on the seam in the ventilation cowling surrounding the reactor head area. The licensee then removed some of the cowling and insulation and discovered a mound of boric acid residue at one edge of the reactor vessel head. A pile of rust-colored boric acid crystals 3 feet by 5 feet by 1 foot high had accumulated on the head, and a thin white film of boric acid crystals had coated several areas of the head and extended 1 to 2 feet up the control rod mechanism housings. The source of the boric acid was reactor coolant leakage through three pinholes in the seal weld at the base for the threaded connection (conoseal) for thermocouple instrumentation. During the previous operating period, reactor coolant leakage had not exceeded 0.4 gallon per minute (gpm). Corrosion damage to the reactor vessel head was caused by borated water that had dripped from the ventilation supports onto the head. The licensee found nine corrosion pits in the ferritic steel vessel head. The pits were 1 to 3 inches in diameter and 0.4 to 0.36 inch deep.

LER Number	31198007
Plant	Salem Unit #2
Event Date	7/30/1998
Abstract	On July 29, 1998, indications of leakage through reactor coolant system (RCS) instrumentation tubing were discovered. The subject tubing is used for RCS flow indication and protection and is an ASME Code Class 2 component. Following initial evaluation of the condition, on July 30, 1998, the Technical Specification for ASME Code Class 2 leaks was entered, and the line was isolated. A four hour notification was made to the NRC in accordance with 10CFR50.72(b)(2)(I). Additional walk-downs resulted in the discovery of leakage indications on the tubing of five other RCS Instrument lines and on tubing in the pressurizer liquid sample line delay coil. Small accumulations of dried boron on the outside of the tubing were the only indications of leakage. The affected tubing is Type 304 stainless steel tubing that contains reactor coolant. The affected lines are ASME Code Class 2 components and are designed to maintain the RCS pressure boundary. The failure mechanism is transgranular stress corrosion cracking initiated from the outside diameter due to the presence of contaminants on the outside surface of the tubing. The source of the contaminants cannot be definitely determined. Corrective

actions taken include replacing the affected tubing. Planned corrective actions include inspecting the Salem Unit 1 tubing during the next outage of sufficient duration, performing swipe testing of exposed stainless steel tubing at both Salem units, cleaning tubing if required, and emphasizing cleanliness requirements with appropriate personnel.

LER Number	36192004
Plant	San Onofre Unit #2
Event Date	2/18/1992
Abstract	Power level - 000%. On 2/18/92, with unit 3 defueled for the cycle 6 refueling outage, a dye-penetrant examination of a pressurizer vapor space level instrument nozzle revealed the presence of a crack. The examination was prompted by earlier observations of rust and boric acid crystals in the vicinity of the nozzle during a walkdown of the reactor coolant system (RCS) following the shutdown. On 3/14/92, unit 2 was shutdown for reasons unrelated to this event. A thorough inspection of the unit 2 nozzles, prompted by the findings at unit 3, revealed similar signs of rust and boric acid crystals at two of the nozzles. The observed leakage was attributed to primary water stress corrosion cracking (PWSCC) of the Inconel 600 material from which the nozzles were fabricated The leaking unit 3 nozzle, as well as the remaining 3 vapor space nozzles in the unit 3 pressurizer, were replaced with nozzles made from Inconel 690, a material less susceptible to PWSCC. An interim repair of the unit 2 nozzles with Inconel 690 was implemented prior to its startup. Since it is likely that these conditions existed during modes of reactor operation in which no primary pressure boundary leakage is allowed, Technical Specification 3.4.5.2a, Reactor Coolant System - operational leakages, is considered not to have been satisfied.

LER Number	36198002
Plant	San Onofre Unit #2
Event Date	1/26/1998
Abstract	On January 26, 1998, during the Unit 2 mid-cycle outage, plant personnel visually inspected all Reactor Coolant System (RCS) nozzles in the hot and cold legs, the pressurizer, and the steam generator channel heads Seven nozzles were identified for repairs. Technical Specification (TS) 3.4.13.a allows no RCS pressure boundary leakage in Modes 1 through 4 The leakage from these nozzles was not measurable and the evidence of leakage could not be detected until the RCS insulation was removed. Based on the existence of boric acid crystals, it is likely that some leaks existed during Mode 1 through 4 operations. Consequently, Southern California Edison (SCE) is reporting these occurrences in accordance with 10 CFR 50.73(a)(2)(I).SCE believes the leakage is from cracks through the nozzle in the heat affected zone of the partial penetration weld of the instrument nozzles. SCE has previously determined that similar cracks were caused by Primary Water Stress Corrosion Cracking (PWSCC) of Alloy 600 materials. SCE replaced the outer half of three nozzles with Inconel 690 material, and repaired four nozzles using

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Mechanical Nozzle Seal Assemblies (MNSA).A complete circumferential failure of an RCS instrument nozzle is not believed to be a credible event. Nevertheless, SCE has verified that the consequences of such a failure would be bounded by the Small Break Loss of Coolant Accident (SBLOCA) analyzed in the UFSAR (multiple simultaneous failures of instrument nozzles is not credible) Consequently, this event had minimal safety significance.

LER Number	36295001
Plant	San Onofre Unit #3
Event Date	7/22/1995
Abstract	Power level - 000%. On July 22 1995, with the Unit in Mode 3, Edison began the Unit 3 cycle 8 refueling outage inspection of the alloy 600 and 690 instrument nozzles. one pressurizer (PZR) level instrumentation nozzle was found with a small amount of boric acid crystals and oxidation present, indicating RCS weepage. On July 26, a radio-chemistry evaluation confirmed that RCS weepage had occurred. Two similar indications were found on RCS hot leg instrument nozzles on July 27, 1995. Based on radionuclide analysis, these RCS leaks were minute and had been inactive for more than a year. These inactive weeps are estimated to have occurred about 500 days prior to discovery at the beginning of Cycle 7 operation, when the unit was in Mode 4 or above. Therefore, Edison is reporting this in accordance with 50.73(a)(2)(I). Edison has concluded that primary water stress corrosion cracking of alloy 600 type materials was the cause of all three RCS pressure boundary leaks. As a precautionary measure, the four PZR vapor space instrument nozzles will be replaced with alloy 690 material. The accessible exterior of the two existing RCS hot leg nozzles will be cut off half way through the RCS hot leg material. New alloy 690 nozzles will be welded to the exterior of the RCS pipe. All repair work is being performed in accordance with ASME Section XI. The leakage area introduced by the complete failure of an instrument nozzle is substantially less than the smallest area evaluated in the UFSAR for small break LOCAs. Thus, the consequences of a failure of an instrument nozzle is bounded by the small break LOCA analyzed in the UFSAR. Edison has concluded that the existence of the RCS leaks noted had minimal safety significance.

LER Number	36297001
Plant	San Onofre Unit #3
Event Date	4/12/1997
Abstract	Power level - 000%. On April 11, 1997, plant operators began reducing reactor power for the Unit 3, Cycle 9 refueling outage. Between April 12-17, 1997, Edison inspected all Inconel Alloy 600 instrument nozzles in the RCS. During this inspection, Edison noted that four RCS nozzles had leaked during plant operation, and a fifth is suspected of leaking. Technical Specification (TS) 3.4.13.a allows no pressure boundary leakage in Modes 1 through 4. If this LCO is not met, this TS requires

the Unit to be in Mode 5 within 36 hours. Based on the existence of boric acid crystals around some of the leak locations, Edison believes it likely, that one or more of the leaks existed during plant operation (more than 36 hours prior to entering Mode 5). Consequently Edison is reporting these occurrences in accordance with 10CFR50.73(a)(2)(I). Based on evaluation of the leak size, leak location, deposition of boric acid crystals, and previous experience with Inconel 600 nozzle leakage, Edison suspects the leakage to be from a crack through the nozzle in the heat affected zone (HAZ) of the partial penetration weld on each of the instrument nozzles. Historically, Edison has determined that similar cracks were caused by Primary Water Stress Corrosion Cracking (PWSCC) of alloy 600 type materials. Cracking of Inconel 600 material is well known and is likely the root cause of these leaks. If, after further analysis, a cause other than provided here is found, this LER will be supplemented with additional details. Edison will replace the outer half of the Inconel 600 material of the original nozzles with Inconel 690 Required welding will be completed in accordance with the ASME III, Class 1 welding guidelines. [Note: This repair is similar to that reported in LER 2-97-004.]

LER Number 36297002
Plant San Onofre Unit #3
Event Date 7/3/1997
Abstract On July 3, 1997, plant personnel inspected the Unit 3 RCS nozzles at 350 psia. One nozzle had an increased amount of white residue, and an isotopic analysis determined the residue was boric acid from the RCS. Three other "suspect" nozzles were re-inspected; two had a slight residue increase, the third did not. Edison assumed the residue from these other nozzles was also boric acid from the RCS. Technical Specification (TS) 3.4.13.a allows no pressure boundary leakage in Modes 1 through 4. If this LCO is not met, this TS requires the unit to be in Mode 5 within 36 hours. Based on the existence of boric acid crystals around some of the leak locations, Edison believes it likely that one or more of the leaks existed during Mode 3 and 4 operations. Consequently, Edison is reporting these occurrences in accordance with 10CFR50.73(a)(2)(I). Edison has previously determined that similar cracks were caused by Primary Water Stress Corrosion Cracking (PWSCC) of alloy 600 type materials. Cracking of Inconel 600 material is well known, and is believed to be the root cause of the leaks reported herein. Based on evaluation of the leak size, leak location, deposition of boric acid crystals, and previous experience with Inconel 600 nozzle leakage, Edison suspects the leakage is from a crack through the nozzle in the heat affected zone (HAZ) of the partial penetration weld on each of the instrument nozzles. These nozzles were originally designed and installed as a one piece nozzle made of Inconel 600 welded with a J-Groove weld on the inside of the RCS piping. Edison replaced the outer half of the nozzles (Inconel 600 material) with Inconel 690 material. Required welding was completed in accordance with the ASME III, Class 1 welding

	guidelines
LER Number	44392026
Plant	Seabrook Unit #1
Event Date	7/14/1992
Abstract	Power level - 100%. This LER is being submitted as a voluntary LER by North Atlantic Energy Service Corporation. On July 14, 1992, Seabrook Station maintenance personnel were performing work on Chemical Volume Control System [CB] demineralizer 2A resin sluice discharge valve, CS-V-93, when it was discovered that three of the four cover bolts had fractured. This bolting configuration caused the valve bonnet to loosen and become cocked. The demineralizer was isolalod and a temporary strongback device was installed on the valve to prevent the plug from being ejected. As a result of this failure, plant walkdowns of similar valves were performed. It was discovered that two additional valves, CS-V-252 and CS-V-742, in close proximity to CS-V-93 each had two fractured cover bolts. CS-V-93 and CS-V-252 are safety related, ASME Class 3 valves, and CS-V-742 is a non-nuclear safety valve. All three valves are three inch stainless steel Xomox [X002] Tufline plug valves which are manually operated with remote reach rods Valves, CS-V-93, CS-V-252, and CS-V-742, are physically located in the Primary Auxiliary Building [NF] demineralizer alley. There were no adverse safety consequences as a result of this event. No radioactive effluents were released to the environment. The root cause of the bolting failures was determined to be due to high material hardness which caused the material to become more susceptible to stress corrosion cracking The station environment provided the necessary moisture for initiation and propagation of the bolt stress cracking. The normal bolt torquing tensile stresses have been determined to be sufficient to contribute to intergranular stress corrosion cracking. North Atlantic has replaced bolting on a total of 158 Xomox Tufline plug valves which had Grade B6 Type 410 stainless cover bolts. This total consists of 64 ASME Safety Class 2 and 3 valves and 94 non-nuclear safety related valves.

LER Number	33587014
Plant	St. Lucie Unit #1
Event Date	10/8/1987
Abstract	Power level - 100%. On October 8, 1987, St. Lucie unit 1 was at mode 1, 100% power and at steady state conditions. While performing a routine 2-hour leak rate surveillance, it was discovered that there was an unidentified reactor coolant system (RCS) leakage greater than one gallon per minute (gpm) (1.09 gpm). At 0529, the nuclear plant supervisor (NPS) declared an unusual event. Operations personnel made a containment entry to investigate the source of leakage. At 0612 hours, a controlled reactor shutdown was started so further investigations could be performed. During this investigation, the sources of the leakage were identified and determined to be less than the 10 gpm allowed by the technical specifications. The unusual event was terminated at 1405 on October 8, 1987. Cause of the event was due to leaking check valve

bonnet and a cracked pipe in the heat affected zone on the 1a1 reactor coolant pump (RCP) lower cavity seal nozzle weld. The root cause of the weld joint failure was due to the previous misalignment of the seal injection piping flange and the RCP lower cavity seal nozzle flange. For corrective actions, the unit was shutdown and required repairs were performed and completed The remaining reactor coolant pumps, 1A2, 1B1, and 1B2 were inspected for proper alignment of the seal injection and lower cavity seal nozzle flanges.

LER Number 33501003
Plant St. Lucie Unit #1
Event Date 4/14/2001
Abstract On April 14, 2001, Unit 1 was in refueling Mode 6 following shutdown for a scheduled refueling outage. During maintenance to replace fixed insulation with removable insulation at the 3/4-inch 1B hot leg instrument nozzle RC-126, a minor through wall reactor coolant system leak was identified at the nozzle. A review of the Alloy 600 nozzle material used at RC-126 indicates that heat NX-0003 was used. There is not industry failure history for this heat; however, Alloy 600 is susceptible to PWSCC and has occurred in similar conditions in the RCS hot leg at St. Lucie Unit 1 and six other CE NSSS units. There are nine uses of this heat in Unit 1, including the one that failed at RC-126. Visual inspection of the other eight nozzles of the susceptible heat NX-0003 was completed and no leakage was identified. Corrective actions include replacement of RCS nozzles RC-126 under ASME Section XI IWA-7000 with a half nozzle design prior to startup. The RCS inspection procedures were reviewed and are effective at identifying the leakage associated with the small-bore PWSCC failures and no changes were required. FPL is developing a replacement schedule for the remaining eight nozzles.

LER Number 38994002
Plant St. Lucie Unit #2
Event Date3/16/1994
Abstract Power level - 000%. On 16 March, 1994 Unit 2 was in mode 6 during a refueling outage. FPL Engineering personnel identified trace amounts of boric acid on the exterior of the Pressurizer steam space C instrument nozzle during an inspection. Subsequently, Quality Control (QC) personnel performed interior dye penetrant examination and identified unacceptable indications at the A, B and C steam space instrument nozzle welds. The D instrument nozzle weld was acceptable. The unacceptable weld indications were in the 'J' weld between the alloy 690 nozzle and the clad on the inside of the Pressurizer. The probable root causes of the condition include: 1) Usage of the Shielded Metal Arc welding process and I-182 filler material which is susceptible to Primary Water Stress Corrosion Cracking. 2) High residual stresses due to multiple nozzle rework and replacements performed in 1987 and 1993. 3) Less than optimum conditions for the welding process during interior Pressurizer repairs performed in 1993. Adverse conditions increased the

likelihood of slag inclusions and lack of weld fusion The corrective actions: 1) FPL Engineering performed a root cause analysis on the condition. 2) A more suitable weld material will be used in repairing the steam space nozzles prior to unit restart. 3) The nozzle repair method will relocate the welds to the exterior of the pressurizer and away from the high residual stress zones. 4) An automated welding machine will be used in the repair efforts. 5) Mechanical Maintenance will coordinate the inspections and repair efforts performed by a contractor with experience in this technique.

LER Number 38995004
Plant St. Lucie Unit #2
Event Date 10/10/1995
Abstract Power level - 000%. On October 10, 1995, St Lucie Unit 2 was in Mode 3 following a shutdown for a scheduled refueling outage. A routine Reactor Coolant System (RCS) visual leak check was being performed in accordance with an approved plant procedure. During the course of the inspection, a utility Quality Control inspector observed that an instrument nozzle located on the 'B' side RCS hot leg exhibited an apparent boric acid buildup indicative of RCS leakage. Although no active leakage was observed, a plant cooldown was continued to Mode 5 within the Technical Specification (TS) time requirements for RCS pressure boundary leakage. Further investigation confirmed that pressure boundary leakage had previously occurred, most probably due to primary water stress corrosion cracking (PWSCC) of alloy 600 material at the instrument nozzle. The corrective actions for this event were: 1) A visual inspection of other RCS instrument nozzles was completed and no additional leakage was found. performed which indicated that no recent RCS, leakage had occurred, but that leakage had occurred at some time in the past. 3) Plant staff will conduct additional testing during nozzle removal to confirm the presence and orientation of the indication. 4) The defective instrument nozzle and other RCS nozzles having the same heat number will be replaced prior to unit startup. 5) Engineering will review the data collected from this inspection for enhancements to the existing RCS nozzle Inspection program and schedule for alloy 600 nozzle replacement.

LER Number 39500008
Plant Summer Unit #1
Event Date 10/12/2000
Abstract On 10/7/00 plant personnel identified an accumulation of boric acid near the "A" loop of the RV. Subsequent inspections revealed small amounts of boron buildup on the weld between the vessel nozzle and the hot leg pipe. Within hours, the suspect area was cleaned up and a PT examination of the pipe identified a 4 inch indication at the weld approximately 3 feet from the vessel between the hot leg piping and the reactor vessel nozzle. The indication was located about 17 inches from the top of the pipe. This pipe has a nominal inside diameter of 29 inches

and is approximately 2.5 inches thick. Subsequent UT examination from the inside diameter identified an axial flaw less than 3 inches long. The same examination determined that the original indication was not the source of the leak. The PT indication were later determined to be steam cutting/boric acid corrosion at the nozzle butter to nozzle interface. The axial flaw was determined to have resulted from the extensive repairs performed during initial installation which created high welding residual stresses in the material, combined with a material susceptible to stress corrosion cracking, and an environment known to cause PWSCC. The welding technology of the codes, standards and processes in use during initial installation did not account for the extent of repairs required on the weld. Weld repairs were completed on February 9, 2001.

LER Number	28098006
Plant	Surry Unit #1
Event Date	3/24/1998
Abstract	On March 24, 1998, with Unit 1 at Cold Shutdown, the B Reactor Coolant Pump (RCP) Motor was being removed for maintenance. During the removal process, it was noted that there was a boric acid build-up on the head of the RCP lower radial bearing Resistance Temperature Detector (RTD) connection. The RTD cap was removed and it was noted that the thermowell was filled with water. This RTD is dry mounted in a thermowell. The thermowell forms part of the Reactor Coolant System (RCS) pressure boundary. A sample of the water revealed that the water was from the RCS indicating a through wall leak of the thermowell. Technical Specification 3.1.C.4 prohibits a non-isolable fault in a RCS component body, pipe wall, vessel wall, or pipe weld. Prior to Unit operation the defect was repaired in accordance with appropriate codes and standards. This event is reportable pursuant to 10CFR50.73(a)(2)(I)(B) for conditions prohibited by Technical Specifications.

LER Number	28095007
Plant	Surry Unit #1
Event Date	9/124/1995
Abstract	Power level - 000%. On September 12, 1995, Unit 1 was at cold shutdown for a scheduled refueling outage. While insulation was being removed from the Unit 1 pressurizer for planned inspections, boron crystals and corrosion products were discovered on the outside diameter of the vessel where two of the four nozzles for the upper instrument nozzles exit. Boroscopic and liquid penetrant inspections were conducted in the four upper nozzles and in two of the five lower nozzles after the attached piping had been removed. These inspections revealed a circumferential crack located approximately 2.5 inches from the inside end of the nozzle in each of the two suspect upper nozzles. The two nozzles were removed and replaced. One nozzle was extracted from the pressurizer and a detailed metallurgical examination of the failure was performed. The actual through wall leak in the nozzle was not recovered

when the nozzle was removed from the vessel wall. As a consequence it was not possible to determine a definitive cause for the leak. However, examination of the material revealed substantial evidence of inside diameter initiated Transgranular Stress Corrosion Cracking (TSCC) and outside diameter Intergranular Stress Corrosion Cracking (ISCC) and TSCC. An analysis was performed that determined there were no potential safety consequences. Therefore, the health and safety of the public were not affected at any time during this event. The identification of cracks in the pressurizer nozzle and the resulting deposits are evidence of through-wall leakage which is in violation of Technical Specifications (TS) section 3.1.C.4. Since Unit 1 was in cold shutdown for a scheduled refueling outage at the time of the discovery, no additional TS limiting conditions of operation were applicable. This event is reportable in accordance with 10 CFR 50.73(a)(2)(I)(B) due to operation in a condition prohibited by TS.

LER Number 28192008
Plant Surry Unit #2
Event Date 12/15/1992
Abstract Power level - 100%. On December 15, 1992, at 0858 hours, with Units 1 and 2 at 100% reactor power, Radiological Protection technicians notified the Unit 2 Senior Reactor Operator (SRO) that a Reactor Coolant System (RCS) leak had developed near the Low Pressure Letdown Flow Transmitter. The leak was determined to be in excess of the maximum RCS leakage rate permitted by Technical Specification (TS) 3.1.C.5. A Limiting Condition for Operation (LCO) requiring hot shutdown within six hours was entered at 0858 hours. The LCO was exited at 0901 hours once letdown was isolated. A four hour LCO was entered at 0901 hours to identify the leak in accordance with TS 3.1.C.2. RCS leakage was verified to be less than 1 gallon per minute (gpm) at 0940 hours and the LCO was exited. The leakage occurred when a section of drain valve tubing for the Low Pressure Letdown Flow Transmitter separated from its fitting. It was determined that the release of radioactivity to the environment was negligible based on indications from the Ventilation System Process Radiation Monitors; therefore, the health and safety of the public were not affected. A Root Cause Evaluation (RCE) is being conducted to determine the exact cause of this event. Recommendations will be implemented from the RCE, as appropriate. This event is reportable pursuant to 10CFR50.73(a)(2)(I)(B).

LER Number 28994001
Plant Three Mile Island Unit #1
Event Date 3/7/1994
Abstract Power level - 075%. Boric acid degradation of pressurizer spray valve (RC-V1) fasteners due to failure to consider pre-load when increasing motor operator torque On March 7, 1994, TMI-1 was operating at reduced power having located and isolated a body-to-bonnet leak from the pressurizer spray valve (RC-V1). RC-V1 was declared inoperable.

Because of boric acid degradation exhibited by RC-V1 fasteners, this event was found to be reportable in accordance with 10CFR50.72(b)(1)(ii) and 10CFR50.73(a)(2)(ii). With RC-V1 isolated, operation was permitted while preparations were made to shut down and repair RC-V1. The plant was shut down on March 17, 1994 and the valve repaired. The root cause was failure to consider the effects on fastener pre-load when the motor operator torque settings were increased. There were no safety consequences. RC-V1 was repaired and other bolted connections were inspected Corrective actions include an evaluation of corrosion resistant fastener materials, programmatic improvements, and training.

LER Number 28901002
Plant Three Mile Island Unit #1
Event Date 10/12/2001
Abstract On October 11 and 12, 2001, following shutdown for a scheduled refueling outage, TMI 1 performed a visual inspection of the RPV head nozzle penetrations per NRC Bulletin 2001-01. The inspection revealed evidence of boric acid buildup around all eight (8) T/C nozzles and boric acid buildup around 12 CRDM nozzles. Based on the visual examination, engineering evaluation determined that all 8 of the T/C nozzles were a source of RCS pressure boundary leakage. Additional NDE on the CRDM nozzles identified that five CRDM nozzles were also a source of RCS pressure boundary leakage and one non-leaking CRDM nozzle that contained unacceptable flaws The cause of the cracks was determined to have been PWSCC. Prior to existing the refueling outage, these nozzles were repaired. The RCS unidentified leak rate before the shutdown did not indicate any significant leakage. A safety assessment concluded that the nozzle cracks did not pose any risk for catastrophic nozzle failure or boric acid damage to the RPV head. Routine qualified visual inspection were determined to be adequate to detect future similar cracks before any significant impact on safe operations can occur.

LER Number None
Plant Turkey Point #4
Event Date March 13, 1987
Abstract On March 13, 1987, personnel at Turkey Point Unit 4 discovered more than 500 lbs. Of boric acid crystals on the reactor vessel head. There also was a large amount for boric acid crystals in the exhaust cooling ducts for the control rod drive mechanisms (CRDMs). After removal of this boric acid and steam cleaning of the reactor vessel head, severe corrosion of various components on the reactor vessel head was noted. This event at Turkey Point Unit 4 has once again demonstrated that boric acid will rapidly corrode ferritic (carbon) steel components and it also again demonstrated that if a small leakage occurs near hot surfaces and/or surroundings, then the boric acid solution will boil and concentrate, becoming more acidic and thus more corrosive. The source of the boric acid crystals was found to be a leaking lower instrument tube seal (conoseal), on one of the incore instrument tubes. This seal is a flanged joint with an oval metal gasket that is held together by clamps bolted in place. This seal, which is inside the CRDM cooling shroud, was observed to have a very small leak as evidenced by some boric acid crystals during a plant outage in August 1986.

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An evaluation by the licensee at that time concluded that plant startup was acceptable provided the seal was again inspected while the plant was shut down for an unrelated problem in October 1986. On March 13, 1987, Westinghouse, the NSSS vendor, completed a review of boric acid corrosion rates, as earlier requested by the licensee, and reported that the corrosion rate might be much faster than assumed when the licensee's evaluation was performed. The leakage from the conoseal apparently ran down one side of the reactor vessel head insulation and much of it leaked under the insulation to the bare reactor vessel head. In addition, a large amount of vapor was apparently carried up into the CRDM cooling coils and ducts where it condensed and deposited boric acid crystals. Of 58 head bolts, 3 are severely corroded above the associated nuts and will be replaced. The CRDM cooling shroud support is severely corroded in the affected sector and the entire shroud will be replaced. The conoseal clamps also were corroded. The reactor vessel head will be removed to inspect for additional damage. The reactor vessel head, bolts, and other components will be non-destructively tested to check for additional damage. (The above abstract was taken from IN 86-108 Supplement 1.)

LER Number	38292002
Plant	Waterford Unit #3
Event Date	3/25/1992
Abstract	Power level - 100%. At 0248 hours on March 25, 1992, Waterford steam electric station unit 3 declared an unusual event due to reactor coolant system unidentified leakage in excess of the Technical Specification 3.4.5.2 limit of 1 gallon per minute. The reactor was shut down and the source of the leakage was subsequently determined to be the packing area of reactor coolant hot leg sample valve RC-104. The packing gland studs on RC-104 failed due to boric acid corrosion. The root cause of this event was use of a material in an application for which it proved inadequate; that is, the studs were made of a material that is susceptible to boric acid corrosion, and the valve was used in a system where possible packing leakage could expose the studs to boric acid. RC-104 will be repaired or replaced during the next refueling outage and the stud material for similar valves will be evaluated. All leakage due to this event was confined to the reactor containment building, and therefore the health and safety of the public and plant personnel was not compromised.

LER Number	38292006
Plant	Waterford Unit #3
Event Date	7/11/1992
Abstract	Power level - 100%. Abstract at 0703 on July 11, 1992, Waterford Steam Electric Station Unit 3 declared an Unusual Event as a result of unidentified reactor coolant system leakage greater than the Technical Specification 3.4.5.2 limit of one gallon per minute. The reactor was shut down and the source of the leakage determined to be the packing area of Reactor Coolant Hot Leg Sample Valve RC-104. This event resulted from the failure of a temporary leak repair made to RC-104 after the valve's packing gland studs failed due to boric acid corrosion on March 25, 1992. As a result, the root cause of this event and the earlier failure

are the same: the use of a material for the studs in an application for which it proved to be inadequate. That is, the valve was installed in a system where possible packing leakage could expose the studs to boric acid despite the fact that the studs were made of a material that is susceptible to boric acid corrosion. RC-104 will be repaired or replaced during the next refueling outage. Also, the stud material for similar valves will be evaluated. All leakage resulting from this event was confined to the Reactor Containment Building and therefore, the health and safety of the public and plant personnel were not compromised.

LER Number 38299002
Plant Waterford Unit #3
Event Date 2/25/1999
Abstract On February 25, 1999, during a planned inspection, Entergy discovered evidence of Reactor Coolant System (RCS) pressure boundary leakage on two Inconel 600 instrument nozzles on the top head of the Pressurizer. Subsequent inspections of the remainder of Inconel 600 nozzles identified 3 more leaking nozzles. One is on RCS Hot Leg #1 RTD nozzle, one is on RCS Hot Leg #1 sampling line, and one is on RCS Hot Leg #2 differential pressure instrument nozzle. No evidence of leaks was found on the RCS Cold Legs or Steam Generators. The apparent cause of the leaks is axial cracks near the heat-affected zone (HAZ) of the nozzle partial penetration welds resulting from Primary Water Stress Corrosion Cracking (PWSCC). The leaking Pressurizer nozzles have been repaired using a welded nozzle replacement. The leaking Hot Leg nozzles have been temporarily repaired using a Mechanical Nozzle Seal Assembly (MNSA) as an alternate repair method under 10CFR50.55a(a)(3)(I). This event did not compromise the health and safety of the public.

LER Number 38200011
Plant Waterford Unit #3
Event Date10/17/2000
Abstract This LER documents three separate cases of RCS pressure boundary leakage discovered during Waterford's 3 refuel 10 outage. The first case of leakage was discovered during inspections on October 17, 2000 and involved evidence of leakage at a pressurizer heater sleeve (F-4). The other two cases of leakage were discovered during inspections on October 19, 2000 and involved evidence of leakage at two of the three MNSA clamps that had been installed during the refuel 9 outage as temporary repairs of leaking RCS nozzles. The conditions are being reported as violations of TS e.4.5.2.a, which allow no RCS pressure boundary leakage. Although it can not be determined exactly when the leakage actually occurred, in one case, it is believed to have occurred some time after a planned outage conducted during June 2000. Inspection (with insulation on) conducted during that earlier outage did not identify MNSA clamp leakage. The three leakage cases were due to 1)PWSCC, 2) a MNSA clamp flange not being flat against the pipe and 3)

a MNSA clamp seating itself, respectively. The conditions have been corrected by plugging the pressurized heater sleeve, and by removing the MNSA clamps and making permanent weld repairs on the nozzles.

LER Number 29597013
Plant Zion Unit #1
Event Date 4/12/1997
Abstract Although this report is not required per 10CFR56.73 it is being submitted voluntarily. Technical Specification Section 4.0.5.a requires that inservice inspection (ISI) of ASME Class 1, 2 and 3 components shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, except where specific written relief has been granted by the Commission pursuant to 10 CFR 50.55a (g)(6)(I). Written relief from the ASME Section XI, 1989 Edition Code Requirement of IWA-5242(a), for the inspection of bolted connections on systems containing boric acid was granted by the NRC in the form of Relief Request CR-13. However, the Relief Request CR-13 alternative examination visual examination (VT-3) of the reactor head bolting with the insulation removed and the system depressurized each outage prior to dismantling of the head was not performed. A review of past refueling outages inspections revealed that this VT-3 alternative examination required by Relief Request inspections CR-13 had not been performed during this current ISI Interval, nor had the inspection designated by the Code been performed. The cause of this event is the failure to revise the ISI database after the Safety Evaluation Report (SER) was received from the NRC approving the use of the CR-13 relief request. This failure of revising the ISI database resulted because there was no process which took this type of information and incorporated it into program documents. By rot having this process in place, it was possible to miss an item such as this inspection requirement identified in relief request CR-13.VT-1, VT-3 and UT inspectors of the Unit 1 Reactor Head Bolting after detensioning was completed for the current outage. In addition, a review of previous outages visual, surface and volumetric inspections performed during the Third ISI Interval was also completed. These additional inspections and reviews concluded that no degradation including degradation due to boric acid of the Reactor Head Bolting had occurred. Consequently, there was no safety impact due to the missed VT-3 inspections.

LER Number 29597025
Plant Zion Unit #1
Event Date 11/24/1997
Abstract On November 24, 1997, during discussions about reactor cavity area inspections, it was determined that Technical Staff Surveillance (TSS) 15.6.21, "Visual Leak Examination of Class 1 Components (Reactor Coolant System Leak Test)" did not include the reactor cavity (Incore penetration) area to be inspected as required in Section XI, IWB-5220, from 1991 to present, due to the area being identified as an inaccessible area. It was subsequently determined that the reactor cavity area is accessible for a VT-2 inspection during Mode 3. The cause of the event was that an inadequate review of the TSS 15.6.21 procedure was performed in 1991. The safety significance of not performing the VT-2 in the reactor cavity during start-up, following refueling outages since 1991, is considered minimal. Corrective actions include revising TSS 15.6.21 to include a requirement to have future changes to the procedure include a Lead ISI Engineer review, to add VT-2 inspections of the reactor cavity area for both units and to perform the VT-2 inspection on Unit 1 and Unit 2 reactor cavity areas prior to unit restart.

APPENDIX F

SUMMARY OF RECURRING ISSUES RELATED TO PREVIOUS NRC LESSONS-LEARNED EFFORTS

The task group reviewed the reports from previous NRC lesson-learned activities to determine if there were issues common to those resulting from the Davis-Besse lessons-learned review. The reports reviewed were:

- "Indian Point 2 Steam Generator Tube Failure Lessons-Learned Report," October 23, 2000
- Report of the Millstone Lessons Learned Task Group, Part 1: Review and Findings," September 13, 1996.
- SECY 97-036, "Millstone Lessons Learned Report, Part 2, Policy Issues"
- "Task Force Report Concerning the Effectiveness of Implementation of the NRC's Inspection Program and Adequacy of the Licensee's Employee Concerns Program at the South Texas Project," March 31, 1995

The staff found several areas where previous assessments had uncovered performance or programmatic weaknesses similar to those uncovered in the Davis Besse review.

The table on the following page summaries the assessment of recurring NRC lessons:

[Note: The lessons and recommendations from the South Texas effort are listed in Section 5 of its report. The recommendations for India Point 2 are listed in a table in Section 9 of its report. The recommendations for the Millstone effort are in a table provided in the appendix of the Part 2 report. As applicable, recommendation numbers from the source documents are provided in the table here for ease of reference.]

Issue From Davis Besse	Commonality to Previous Lessons or Recommendations	NRC Follow up
Closeout of inspection findings before licensee implementation of corrective actions	Millstone (items 4, 6)	
Program guidance for assessing long-standing hardware problems	South Texas Indian Point-2 (item 5e)	
NRC Inspector/reviewer skills, abilities, experience	Indian Point-2 (items 5b, 5c) Millstone (item 14) South Texas	
Process to verify information	Millstone (item 2) Indian Point-2 (item 6d)	
NRC review of routine reports	Indian Point-2 (item 6c)	
NRR/regional Office interaction during safety evaluation development	Indian Point-2 (item 6d)	
Specific review guidance	Indian Point-2 (item 6a)	
Integration of Inspection findings	South Texas	
Performance review process	Indian Point-2 (items 5a, 5e, 5f) Millstone (items 3, 13, 15) South Texas	
Inadequate Industry Guidance	Indian Point 2 (item 2)	
Inadequate requirements in licensing basis	Indian Point 2 (item 3)	

1.0 INTRODUCTION

1.1 Objective

The NRC has conducted a number of lessons-learned reviews for addressing regulatory process issues associated with significant plant events or safety performance conditions and issues. Consistent with this practice, the NRC's Executive Director for Operations (EDO) directed the formation of an NRC task force in response to the issues associated with the extensive degradation to the pressure boundary material of the Davis-Besse Nuclear Power Station (DBNPS) reactor pressure vessel (RPV) head. The objective of the Davis-Besse Reactor Vessel Head Degradation Lessons-Learned Task Force (task force) is defined in a publicly available NRC memorandum, dated May 15, 2002 from William D. Travers, EDO, to Arthur T. Howell III, the task force team leader.

This memorandum and attachment describe the approach and charter for the inter-office task force to assess the lessons-learned related to the degradation of the DBNPS RPV head that was identified by representatives of FirstEnergy Nuclear Operating Company (FENOC), the licensee for DBNPS, on March 5, 2002. The objective of this effort was to conduct an independent evaluation of the NRC's regulatory processes related to assuring reactor vessel head integrity in order to identify and recommend areas for improvement applicable to the NRC and the nuclear industry. In the context of this effort, independent is defined as NRC staff members who have not had any recent substantive involvement in regulatory matters pertaining to DBNPS.

1.2 Scope

The task force conducted review activities in the following five areas: 1) reactor oversight process issues; 2) regulatory process issues; 3) research activities; 4) international practices; and 5) the NRC's Generic Issue process. In reviewing these five areas, the task force conducted fact finding at DBNPS in order to determine what pertinent plant information was available for processing by the applicable NRC requirements, programs, processes and procedures. The task force conducted review activities in the NRC headquarters and regional offices. The following specific areas were reviewed:

- NRC Inspection Program and Implementation
- NRC Plant Safety Performance Assessment Process and Implementation
- NRC Enforcement Guidance and History
- NRC Reporting Requirements
- Allegation History of FENOC Nuclear Plants
- NRC Regulatory Requirements Involving Reactor Coolant System Leakage and Boric Acid Corrosion Control
- NRC Licensing Review Processes and Implementation
- NRC Operating Experience Review Process and Implementation
- Research Activities
- NRC Generic Communication Process and Implementation
- NRC Generic Issue Process and Implementation
- International Experience and Practices

- Industry Guidance for Managing Regulatory Commitments
- Industry Technical Guidance and Initiatives

The task force conducted a limited review of past NRC lessons-learned review reports to determine whether there were any recurring lessons that were applicable to this issue. These included. 1) Indian Point 2 Steam Generator Tube Failure Lessons-Learned Report; 2) Task Force Report Concerning the Effectiveness of Implementation of the NRC's Inspection program and Adequacy of the Licensee's Employee Concerns Program at the South Texas Project, and 3) Millstone Lessons Learned Task Group Report, Part 1: Review and Findings, and Part 2: Policy Issues. The results of this review are documented in Appendix F.

The task force did not conduct a detailed technical review of the DBNPS nozzle cracking wastage mechanisms since these areas are the focus of other NRC review activities. The task force reviewed the results of the NRC's Augmented Inspection Team (AIT), and considered the available information associated with the licensee's various root cause determination efforts.

Since the task force was primarily concerned with why the DBNPS reactor pressure vessel head degradation was not prevented, it did not focus on the NRC's actions subsequent to the time of discovery of the problem. Nevertheless, during its review, the task force identified a number of issues associated with the NRC's response to the identified condition. These issues are documented in the report, and, in some cases, are specifically addressed by recommendations.

The task force coordinated its review activities with other related on-going reviews being conducted by the Oversight Panel that was formed in accordance with NRC Inspection Manual Chapter 0350, "Oversight of Operating Reactor Facilities in an Extended Shutdown as a Result of Significant Performance Problems," the NRC Office of Investigations, and the NRC Office of the Inspector General, as well as other NRC offices.

The task force conducted a public meeting near the DBNPS site on June 12, 2002 and conducted another public meeting in the NRC Headquarters Offices on June 19, 2002 to solicit public comments on the scope of the task force review activities. The following is a summary of the comments received by those who participated in the meetings:

- A comment that there is a linkage between the RPV head degradation event and the significant decrease in DBNPS staffing levels over the past years;
- A comment that there are some DBNPS lessons-learned form the 1985 loss of auxiliary feedwater event that should have precluded the RPV head degradation event;
- A comment that the task force completion schedule may not be adequate to support a thorough review;
- A comment that the DBNPS RPV head degradation event could be attributed mainly to plant implementation issues;
- A comment that a review of the DBNPS Updated Final Safety Analysis Report did not reveal any discussion of the analyses of safety issues performed in response to NRC requests associated with four specific NRC generic

communications, which appears to represent noncompliance with 10 CFR 50.71(e);

- A comment that questioned the validity of risk assessments conducted over a short duration (i.e., the period between December 31, 2001 and February 16, 2002), and,
- A comment that questioned the relevance of calculations demonstrating the unlikelihood of the RPV head stainless steel cladding from catastrophically failing under both normal and transient pressure loading relative to the NRC significance determination of the DBNPS RPV head degradation.

The task force considered all these comments. Several of them were specifically included in the detailed review plans discased in Section 1.3.

The charter was revised three times during the course of the task force's review activities. These revisions were made to address the addition of observers from the State of Ohio, changes to the task force team composition, and a change to the task force review schedule.

1.3 Preparation, Review and Assessment Methodologies

The task force effort was divided into three phases: 1) the preparation phase; 2) the review phase; and 3) the assessment and documentation phase. Discrete scheduler milestones were established for each of these phases. Additionally, the task force was organized into two distinct groups. One group focused principally on DBNPS fact finding and the applicable regulatory programs, processes, and implementing procedures involving inspection, enforcement, industry operating experience, allegations, and plant safety performance assessment A second group focused principally on the scope of the applicable requirements, licensing review processes, the industry process for managing regulatory commitments, applicable industry technical guidance and initiatives, international experience and practices, research activities, and the NRC's Generic Issue process.

During the preparatory phase, a number of activities were conducted to facilitate the review and assessment phases. The task group discussed the scope, objective and specifics of the charter with a number of NRC managers and staff to establish potential lines inquiry to be considered during the review. Coordination briefings were conducted with other NRC offices, as well as representatives from the State of Ohio and a representative of Ottawa County, Ohio. The NRC's Office of Enforcement provided a summary of the DBNPS enforcement history, as well as an analysis of enforcement actions involving Alloy 600 nozzle cracking, reactor coolant pressure boundary leakage, and boric acid corrosion of carbon steel components. The Agency's Allegation Coordinator provided a summary of allegations for DBNPS as well as other FENOC nuclear plants. Orientation briefings and training were provided to the task force members. The Oakridge National Laboratory compiled a summary of NRC reportable events involving reactor coolant system pressure boundary leakage and boric acid corrosion degradation. Licensee, NRC, and industry documents and records were obtained and reviewed in order to develop detailed review plans. These plans identified specific items to be considered for review, including pre-identified issues, as well as specific individuals to be interviewed. The NRC and the State of Ohio established an agreement which governed the observation of the task force's activities by representatives of the state. As discussed in Section 1.2, two public meetings were conducted to obtain public comments on the task force charter.

During the review phase, the task force conducted independent fact finding at the DBNPS site, and conducted review activities in all four regional offices and the headquarters offices, either in person or telephonically. These review activities principally involved the interviews of personnel and the review of records.

While at the DBNPS site, members of the task force reviewed licensee records, interviewed approximately 45 licensee managers and staff members, and toured the containment building and other selected areas of the facility. A representative of the State of Ohio observed the task force's review activities at DBNPS.

The DBNPS fact finding focused on a review of the reactor vessel head degradation condition and related issues, such as: 1) reactor coolant system (RCS) leakage history; 2) the symptoms associated with active RCS leaks; 3) the boric acid corrosion control program; 4) precursor events, with emphasis on a 1993 issue involving the boric acid corrosion wastage of a D steam generator inspection port caused by a leak of the reactor head vent flanged connection, and a 1998 issue involving the boric acid corrosion wastage of three inadvertently installed carbon steel pressurizer spray valve nuts; 5) the licensee's documented submissions and actions in response to key NRC generic communications, such as Generic Letter (GL) 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," NRC GL 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," and NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles."

As part of the on-site fact finding at DBNPS, the task force reviewed licensee policies, programs, processes, and activities associated with items 1 through 5 noted above. This included the following: oversight activities, including quality assurance audits, performance indicators, line self-assessments, third-party assessments, offsite nuclear review board assessments, action and improvement plans, and root cause analyses associated with this event; staffing and budgeting; outage scoping and scheduling; corrective actions; employee concerns (Ombudsman); training; regulatory commitment management; internal and external industry operating experience review; plant operations; maintenance and testing; plant and design engineering; radiological protection; licensing and compliance; and licensee involvement in the Babcock & Wilcox Owners Group (BWOG). Appendix C documents the index of licensee records requested and reviewed by the task force.

The task force interviewed approximately 75 NRC employees from all four NRC regional offices and the NRC's headquarters offices. Additionally, the task force conducted limited review activities involving other B&W plants in three other NRC regions, as well as two other plants in NRC Region III. For each of these plants, the task force reviewed: licensee actions in response to NRC Generic Letters 88-05 and 97-01; or NRC employee site visits; or both. The task force reviewed NRC documents of interest, which are also listed in Appendix C.

The task force interviewed approximately 10 other individuals, either in person or telephonically, from several external organizations. These organizations included the Nuclear Energy Institute (NEI), Framatome Technologies, Inc., the BWOG, the Electric Power Research Institute (EPRI), and IPSN (the French nuclear regulatory authority) of France.

The assessment phase consisted of a series of team meetings and independent in-office review activities. The task force used techniques that were similar to those used during past NRC Incident Investigation Team and Diagnostic Evaluation Team reviews. These included the identification of basic facts; conclusions categorized by program, personnel or hardware relationships; contributing and root causes; and recommendations.

Figure 1-1 NRC Organization

Figure 1-2 Station Organization