Appendix E

Primary System Leakage and Boric Acid Corrosion Operating Experience at U.S. Pressurized Water Reactors (1986-2002)

E.1 BACKGROUND INFORMATION

The task force reviewed domestic and international operating experience for the period from 1986 through the first quarter of 2002. For the period of interest, 73 pressurized water reactors (PWRs) were included in the sample. The task force also reviewed the NRC's generic communications related to boric acid issues which athe agency issued since 1980, to determine what guidance the NRC provided to the industry, and whether Davis-Besse Nuclear Power Station (DBNPS) utilized the guidance. Acronyms used in this appendix are defined in Section E.6.

E.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. The task force entered this information into a database and sorted it to identify any trends and patterns. Licensee Event Reports (LERs) were the primary source of data regarding boric acid leakage events. Two additional events were added to the database because they involved boric acid leakage and reactor pressure vessel (RPV) head wastage, but were not recorded in an LER. Each operating experience document may have discussed more than one component or system, or may have applied to more than one unit. In addition to listing the component that was affected by the boric acid leak, the task force sorted other information by nuclear steam system supplier (NSSS) designer, design type, plant operating age, number of operating years at the time of the event report, and year of occurrence.

E.2.1 Numerous Boric Acid Leakage and Corrosion Events Have Been Documented

Figure E.2-1, "Reported Areas Involving Boric Acid Leakage (1986-2002)," lists each component that experienced a boric acid leak, or was affected by a boric acid leak. As the figure shows, the most prominent events involving boric acid leakage described in 15 documents related to control rod drive mechanism (CRDM) leaks, 13 related to reactor coolant system (RCS) nozzle leaks, 9 related to pressurizer (PZR) instrumentation nozzle leaks, and 7 each related to RCS valve leaks, RCS instrumentation leaks, and PZR heater sleeve leaks. Other less prominent events are described in four documents related to corrosion of the steel containment vessel, four related to RCS nozzle leaks, three events related to wastage of the RPV head, and three related to wastage of the PZR.

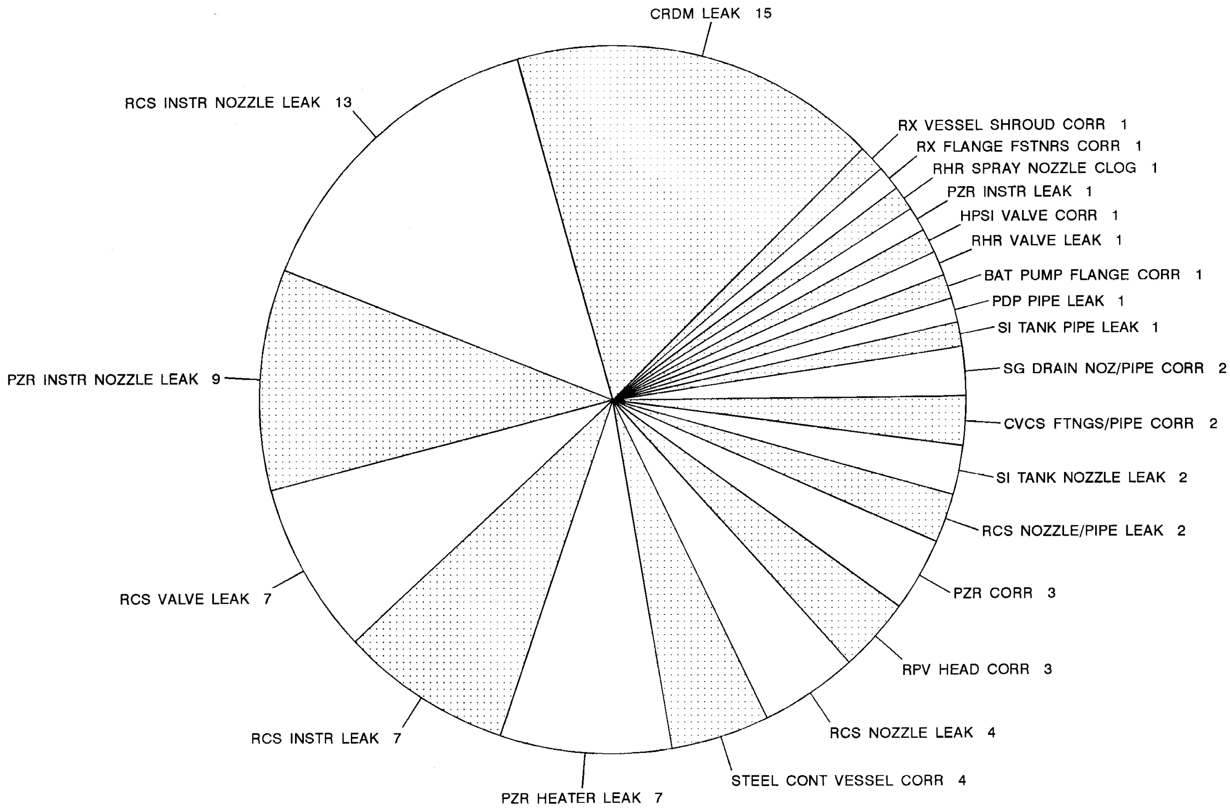


Figure E.2-1. Reported Areas Involving Boric Acid Leakage (1986-2002)

E.2.2 Number of Operating Years Prior to Discovery of a Boric Acid Event Is Random When Considering All Components

Figure E.2-2, “Number of Operating Years Prior to Event Occurrence,” displays an even distribution of boric acid leakage events. This figure lists the plants that have reported a boric acid leak and the number of years of operation prior to the discovery of the leak. When these events are taken as a group, it appears that a plant is equally likely to experience a boric acid leak after only a few years of operation, as it is to experience a leak after a long period of operation. In general, however, smaller components take longer to develop leaks than do larger components. This observation is evident in subsequent figures.

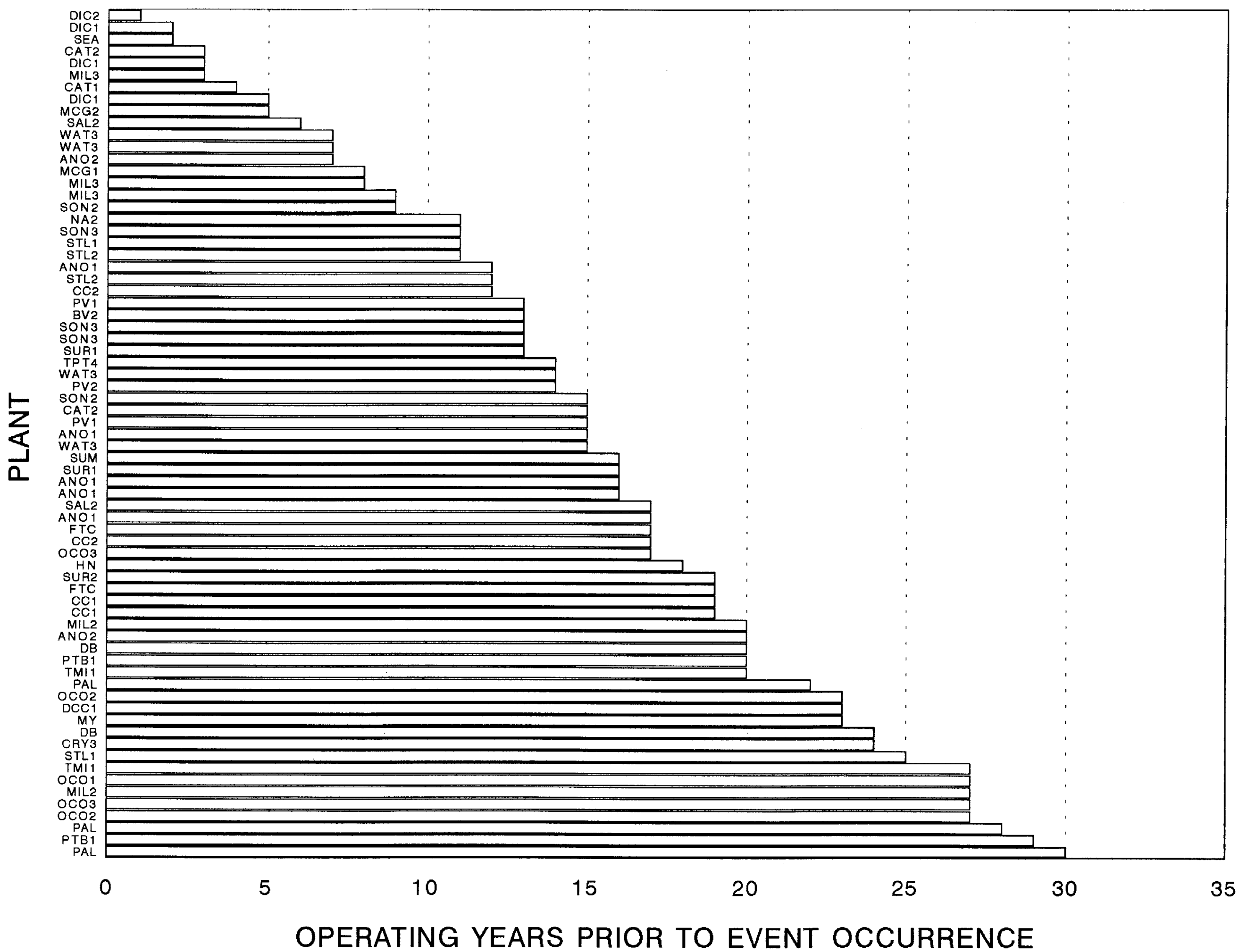


Figure E.2-2. Number of Operating Years Prior to Event Occurrence

E.2.3 Babcock & Wilcox and Combustion Engineering Plants Are Highly Susceptible to Boric Acid Leakage and Corrosion

As shown in Figure E.2-3, “Percent of NSSS Design Manufacturers Reporting Boric Acid Leakage,” Babcock & Wilcox (B&W) and Combustion Engineering (CE) plants appear to be highly susceptible to boric acid leakage and corrosion. In fact, 100 percent of B&W plants have reported boric acid related problems. Combustion Engineering plants were divided into the older CE plant design (12 units total) and the newer CE80 design (3 units total) to determine whether the designs exhibited any differences in susceptibiilty. As shown in the figure, 100 percent of the older CE plants reported boric acid leakage problems, while 67 percent of the CE80 design (two of three units) reported boric acid leakage problems.

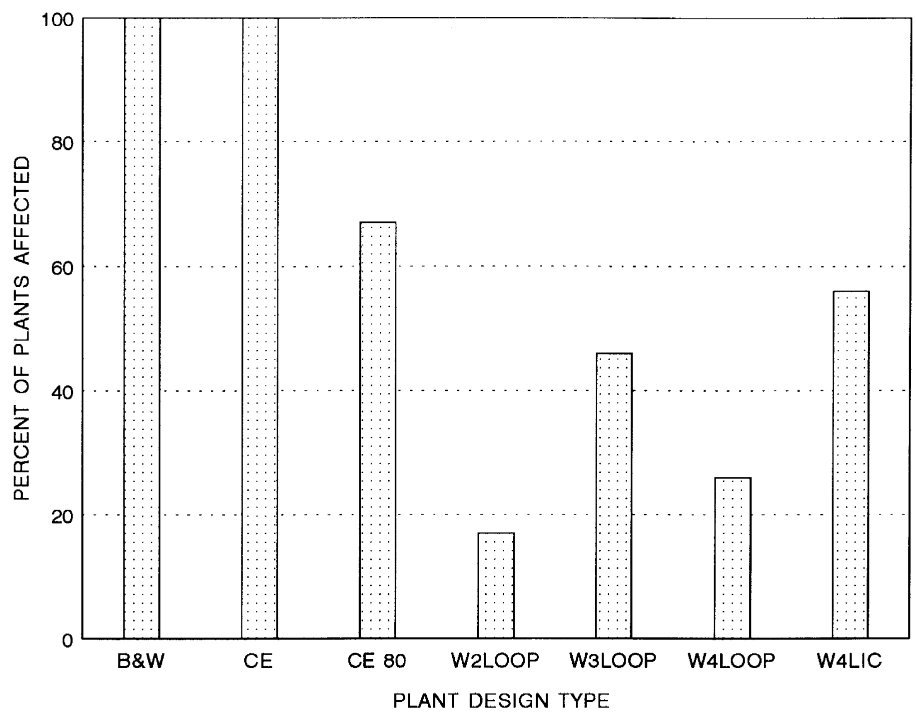


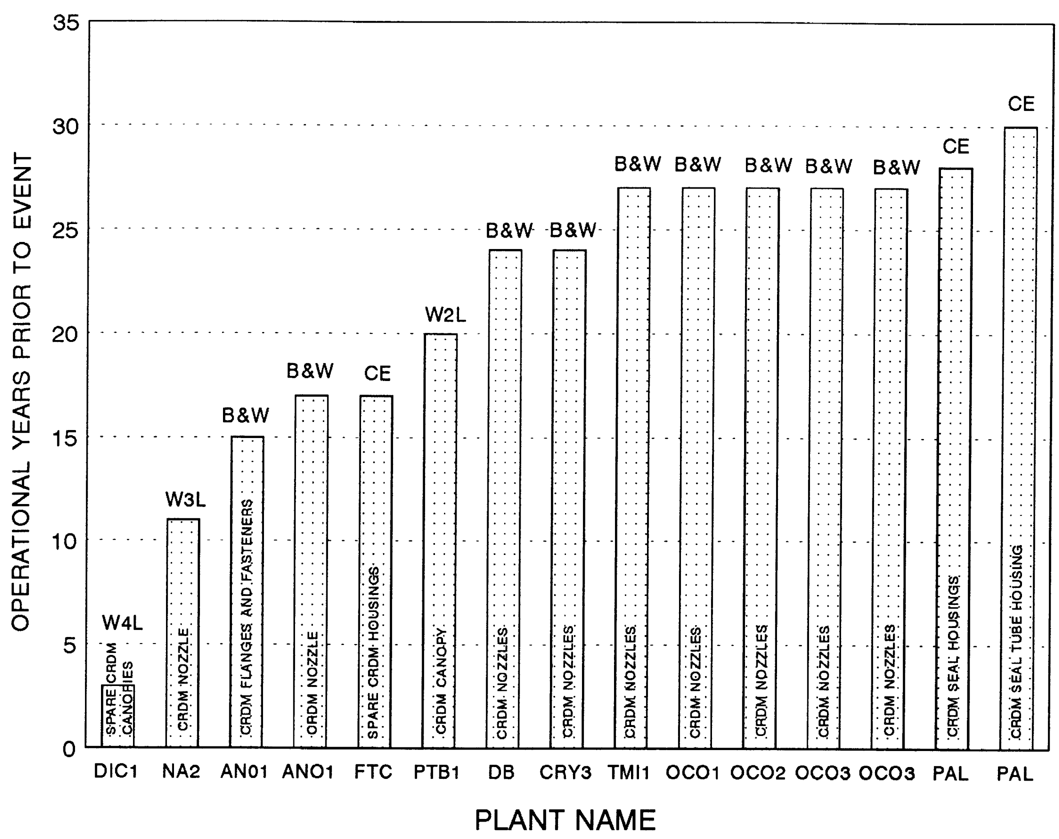
Figure E.2-3. Percent of NSSS Design Manufacturers Reporting Boric Acid Leakage

E.2.4 Westinghouse-Designed Plants Are Somewhat Less Susceptible to Boric Acid Leakage than Other PWR Plants

Figure E.2-3 also shows that Westinghouse plants are less susceptible to boric acid leakage than other PWR designs. The Westinghouse group exhibited significant differences in operating experience. The older Westinghouse two-loop (W2LOOP) plants faired the best, with 17 percent (6 plants total) reporting boric acid leakage problems, while the four-loop ice condenser (W4LIC) version faired the worst, with 56 percent (9 plants total) reporting problems. Of the Westinghouse three-loop (W3L) plants, 46 percent (13 plants total) reported boric acid leakage problems, while 26 percent (23 total) the four-loop (W4L) plants had reported boric acid leakage problems.

E.2.5 Control Rod Drive Mechanism Leakage Is Dominated by B&W Plants

As shown by Figure E.2-4, "Control Rod Drive Mechanism Leakage," B&W-designed plants dominate CRDM leakage. The task force reviewed 15 documents related to CRDM leakage, of which 9 described events that occurred at B&W plants. 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 E.2-4 shows the components that 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 sample of 73 PWRs, and approximately 20 percent of the event reports (3 of 15 reports).



Figur e
E.2-4. Control Rod Drive Mechanism Leakage

E.2.6 Extensive VHP Nozzle Cracking and Leakage at B&W Plants

Table E.2-1, “VHP Nozzle Cracking Experience at B&W Plants,” provides information on the crack location on the RPV head, crack type, extent of nondestructive examination (NDE) other than visual examinations of the CRDMs, number of operating years prior to the event report, and the event date. As shown in Table E.2-1, 6 percent of their reactor vessel head penetration (VHP) nozzles in B&W plants developed through wall cracks, 100 percent of B&W plants had axial VHP nozzle cracks, and 86 percent of B&W plants experienced circumferential cracking in at least one VHP nozzle.

Figure E.2-5, “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, DBNPS was the last B&W plant to report cracking.

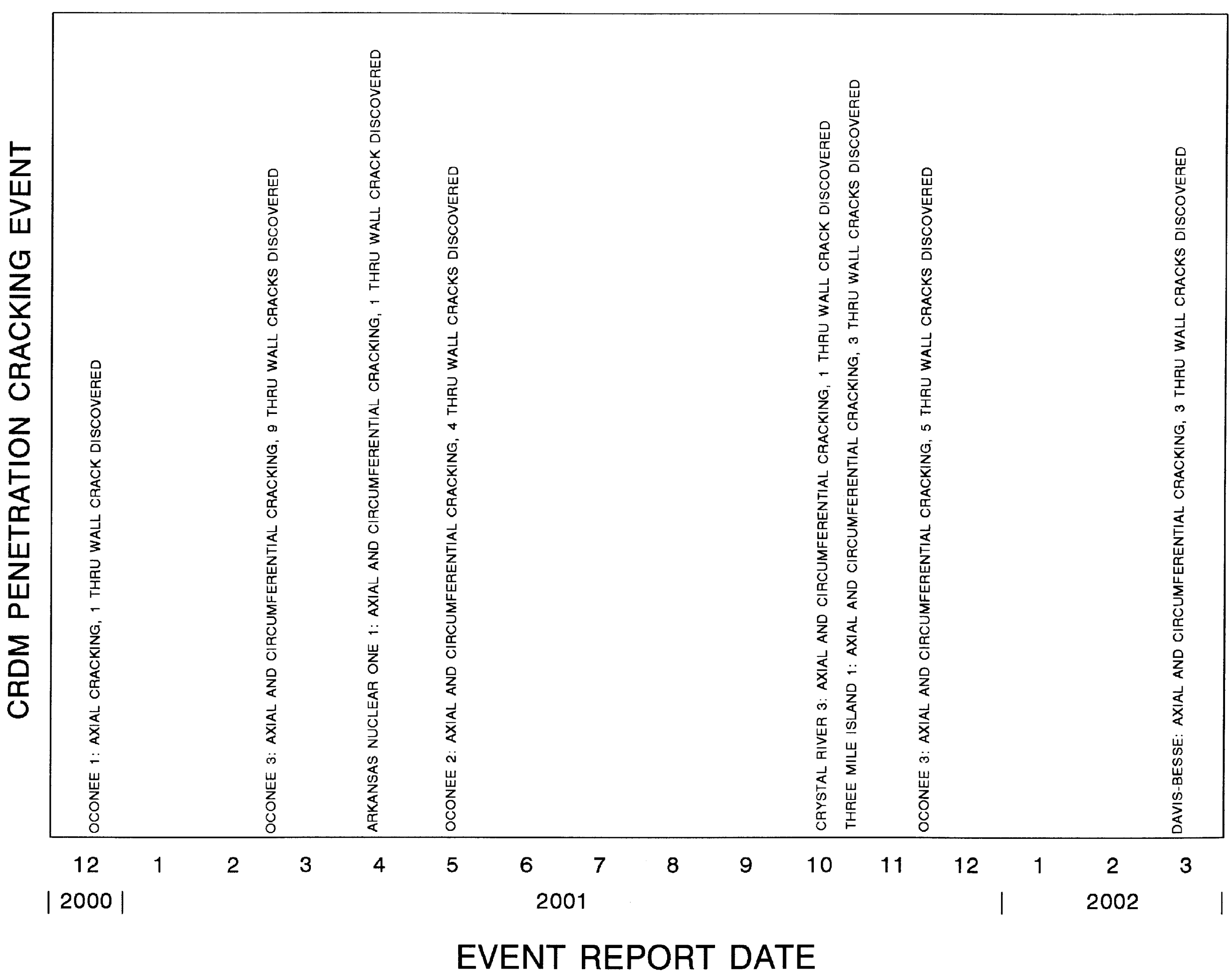


Figure E-2-5. VHP Nozzle Cracking Timeline for B&W Plants

Table E.2-1. VHP Nozzle Cracking Experience at B&W Plants

CRDM ROW*	CRDMs PER ROW	TOTAL	OCO1	OCO3	ANO1	OCO2	CRY3	TMI1	OCO3	DB	PERCENT (%) OF TOTAL WITH CRACKS
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	2	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 (other than visual)
OPER YEARS PRIOR TO EVENT			27	27	17	27	24	27	27	24	
EVENT DATE			12/4/00	2/18/01	3/26/01	4/28/01	10/01/01	10/12/01	11/12/01	2/27/02	

*Row 1 includes CRDM #1; Row 2 includes CRDMs #2-9; Row 3 includes CRDMs #10-25; Row 4 includes CRDMs #26-45; Row 5 includes CRDMs #46-69.

E.2.7 Components Having the Most Prevalent Boric Acid Leakage Issues

The task force reviewed operating experience to determine the average number of operating years prior to discovery of boric acid leakage problems. In doing so, the task force determined the operating time to leak discovery by comparing the event date with the date that the plant obtained its operating license from the NRC. Figure E.2-6, "Average Number of Operational Years Prior to Leakage Event for Selected Components," provides several insights regarding five of the most prevalent leakage areas, including CRDM nozzle leakage (15 reports), RCS instrumentation nozzles (13 reports), PZR instrumentation nozzles (9 reports), PZR heater sleeves (7 reports), and RCS instrumentation (7 reports). Most reports described multiple occurrences of leakage. These events and the operational experience to be gained were available to DBNPS. The licensee for DBNPS relied substantially on industry susceptibility models to postpone VHP nozzle inspections. As shown from the operational experience data, DBNPS 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 DBNPS' discovery of leakage was 24 years, which exceeded the average time period.

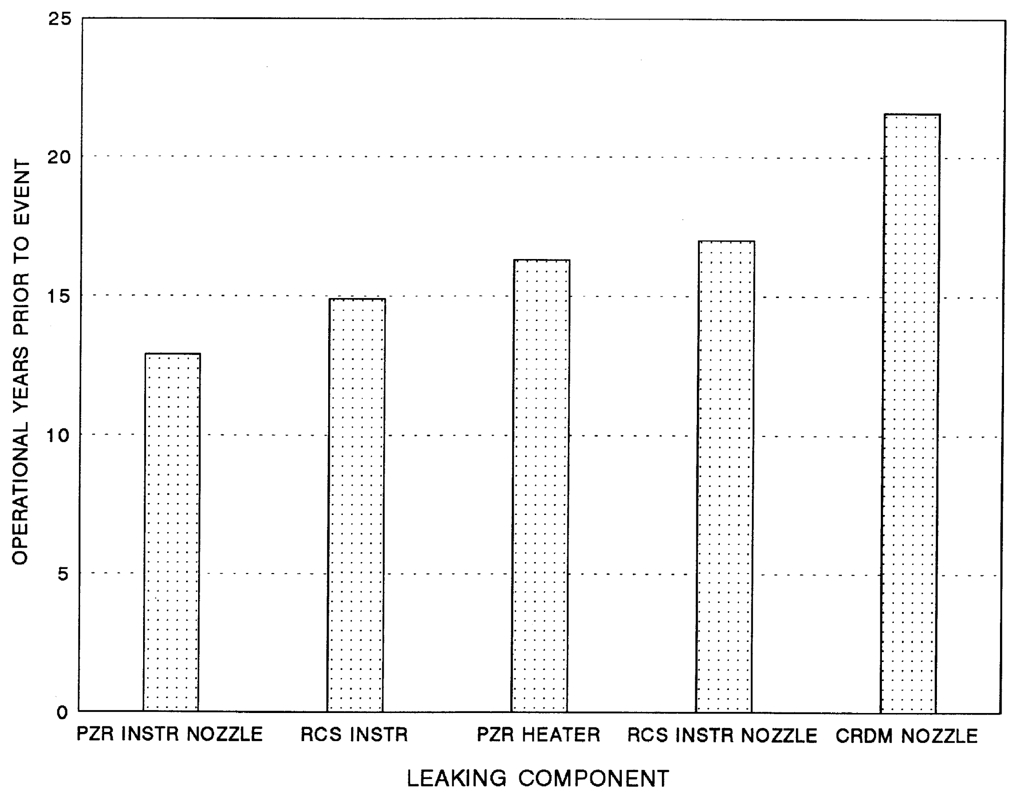


Figure E.2-6. Average Number of Operational Years Prior to Leakage Event for Selected Components

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

Figure E.2-7, “Reactor Pressure Vessel Head Base Metal Wastage Events,” shows those plants that have experienced RPV corrosion (beyond surface metal corrosion). The figure also shows the operating years prior to event occurrence. The event at Turkey Point, Unit 4, in March 1987 was the major reason that the NRC issued IN 86-108, Supplement 1, in April 1987, and the event at Salem, Unit 2, in August 1987 was the major reason for issuing IN 86-108, Supplement 2, in November 1987.

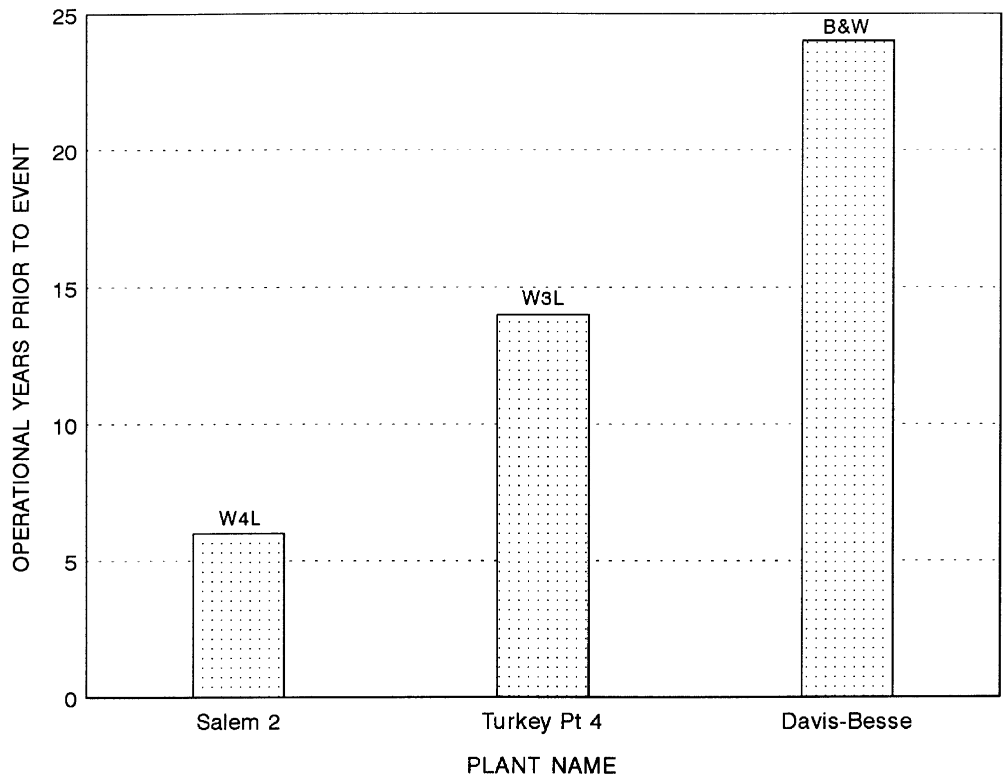


Figure E.2-7. Reactor Pressure Vessel Head Base Metal Wastage Events

E.2.9 Pressurizer Vessel Wastage Events Caused by Boric Acid Corrosion

Figure E.2-8, “Pressurizer Vessel Base Metal Wastage Events,” shows those plants that have experienced pressurizer vessel wastage (beyond surface metal corrosion). The figure also shows the number of operating years prior to event occurrence. These events, including their lessons learned, in conjunction with RPV wastage events indicate that boric acid corrosion of high-temperature components is possible, and should be assessed.

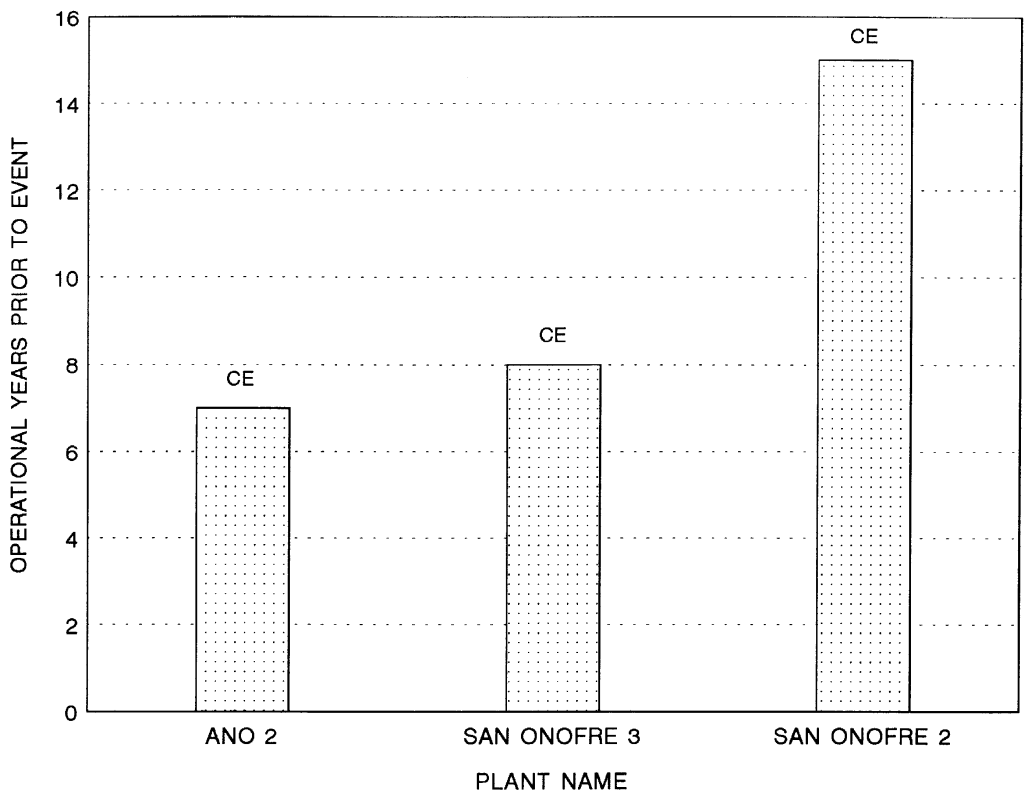


Figure E.2-8. Pressurizer Vessel Base Metal Wastage Events

E.2.10 Reactor Coolant System Nozzle Leakage Operational Experience

Miscellaneous RCS nozzle leakage has occurred in varied locations. Figure E.2-9, “Reactor Coolant System Nozzle Leakage Events,” shows that the larger nozzles take longer to develop leakage. The figure also shows that no one NSSS vendor dominates. Repetitive leakage from similar components is not evident.

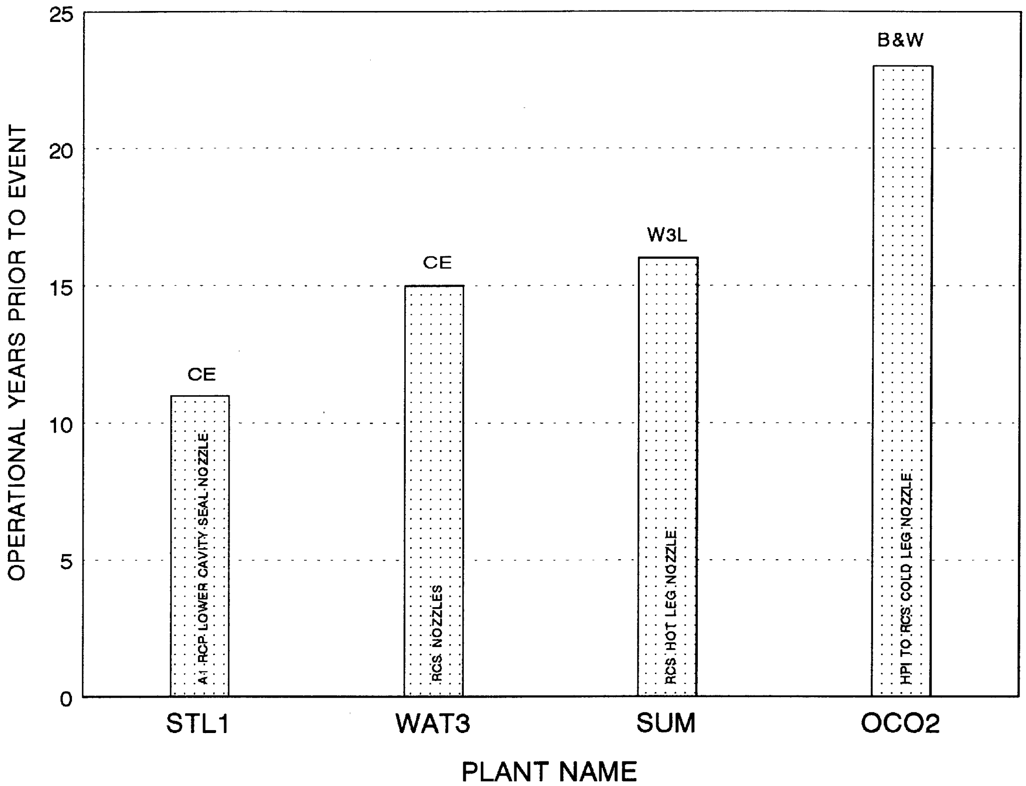


Figure E.2-9. Reactor Coolant System Nozzle Leakage Events

E.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. The recorded events do not indicate repetitive failures of similar components. Two of the events occurred at Westinghouse three-loop plants, while three events occurred at Westinghouse four- loop plants. See Figure E.2-10, “Reactor Coolant System Instrumentation Leakage,” for a brief description of the event and the number of years of operation prior to each. Notably, five of the seven events occurred after 15 to 20 years of operation.

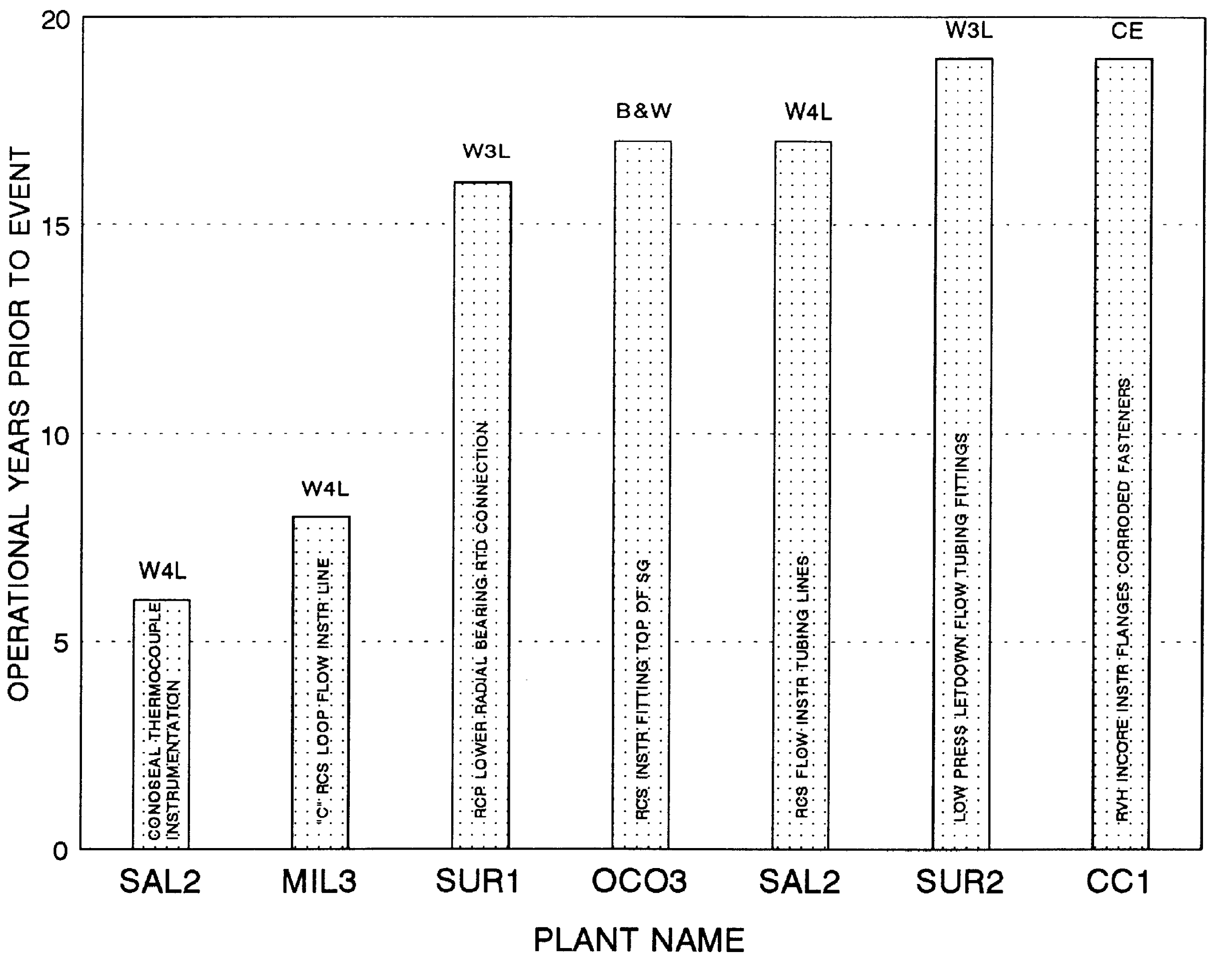


Figure E.2-10. Reactor Coolant System Instrumentation Leakage

E.2.12 Combustion Engineering Plants Dominate Pressurizer Instrumentation Nozzle Leakage

As shown in Figure E.2-11, “Pressurizer Instrumentation Nozzle Leakage,” CE plants dominate the recorded events. Seven of nine PZR instrumentation nozzle leakage events occurred at CE plants. Most of the events involved PZR level instrumentation. Most (five of nine) of the PZR instrumentation events occurred between 11 and 14 years of operation.

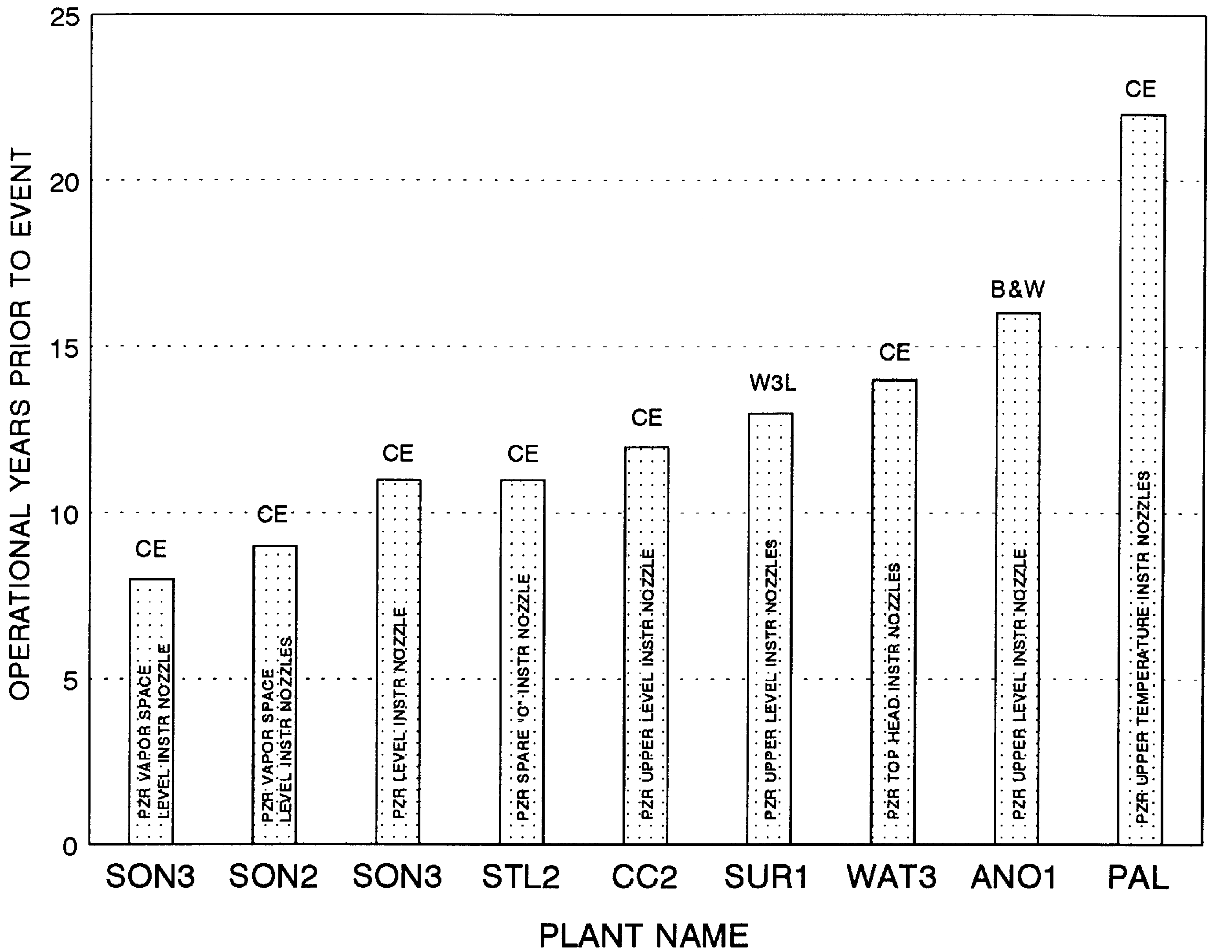


Figure E.2-11. Pressurizer Instrumentation Nozzle Leakage

E.2.13 Combustion Engineering Plants Accounted for All Reported Events of Pressurizer Heater Sleeve Leakage

Figure E.2-12, “Pressurizer Heater Sleeve Leakage,” shows that CE plants dominated the recorded events, comprising 100 percent (seven of seven) of the events. The event at Calvert Cliffs, Unit 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 PZR. Other events involving PZR heater sleeves were less severe.

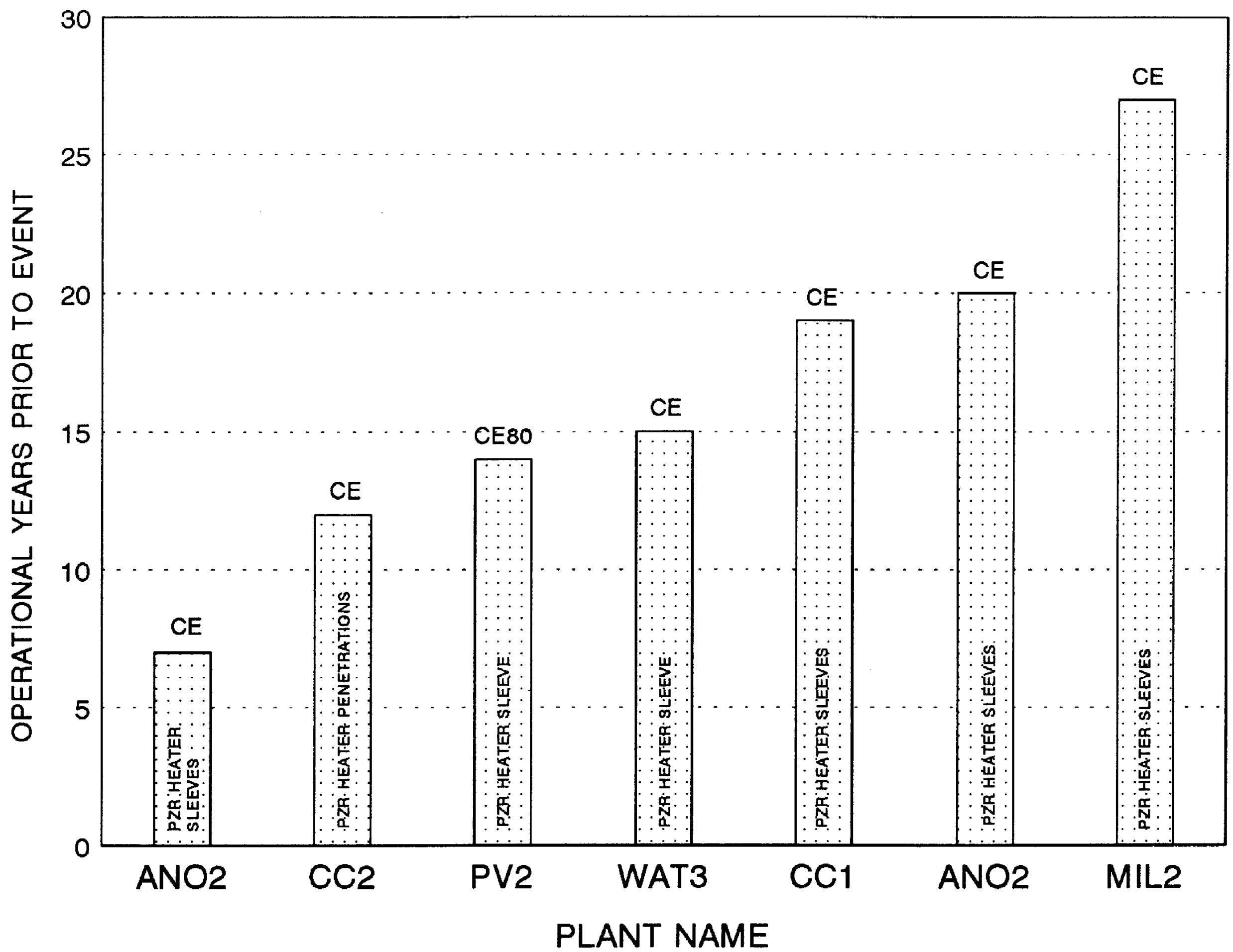


Figure E.2-12. Pressurizer Heater Sleeve Leakage

E.2.14 Combustion Engineering Dominates Reactor Coolant System Instrumentation Nozzle Leakage

As shown in Figure E.2-13, "Reactor Coolant System Instrumentation Nozzle Leakage Events," CE plants dominated the recorded events, representing 9 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. Of the 13 instrumentation nozzle events, 9 occurred between 11 and 16 years of operation. Most of the nozzle cracking was attributed to primary water stress corrosion cracking (PWSCC).

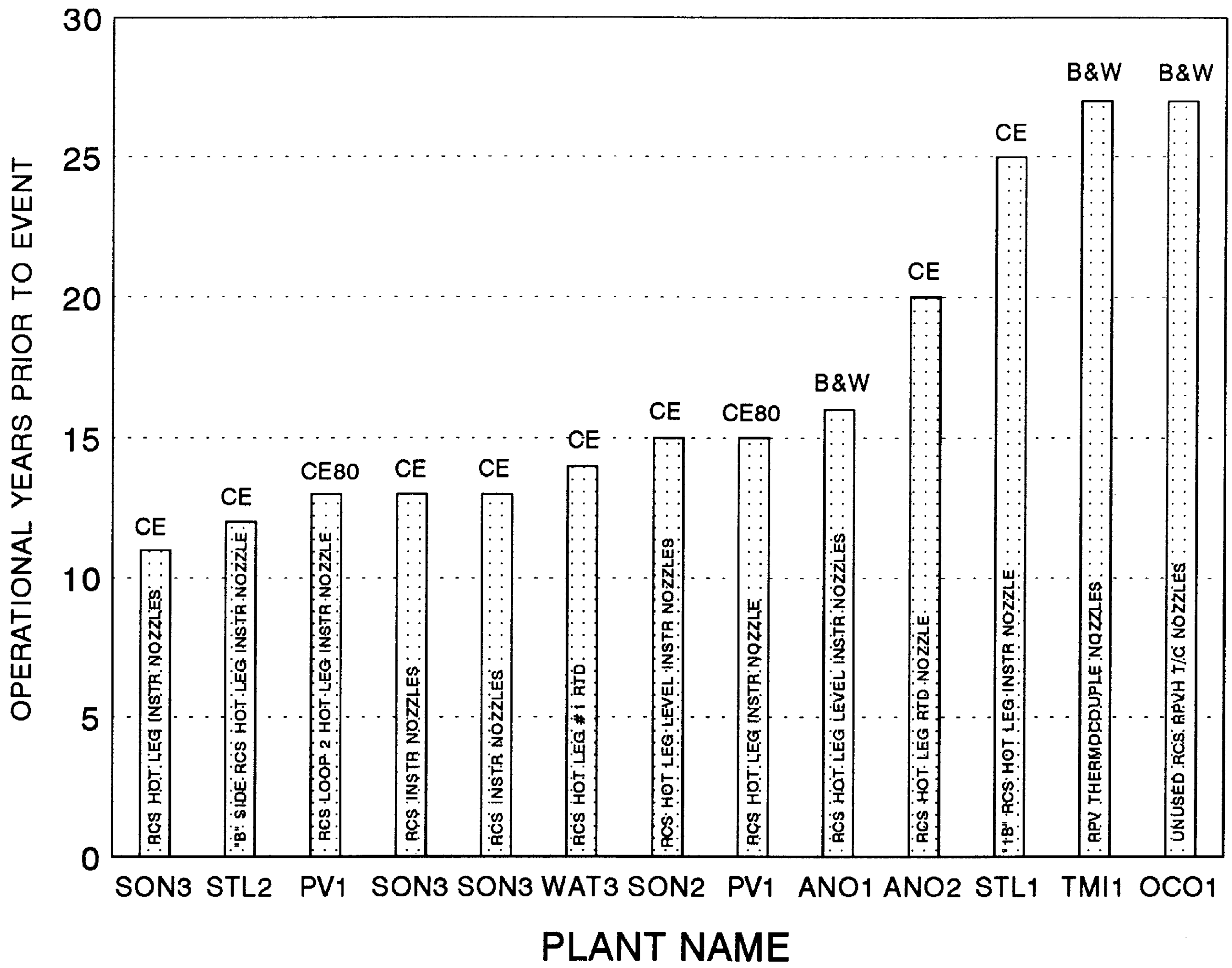


Figure E.2-13. Reactor Coolant System Instrumentation Nozzle Leakage Events

E.3.0 OPERATIONAL EXPERIENCE INFORMATION AND GUIDANCE PRESENTED THROUGH THE NRC GENERIC COMMUNICATION PROCESS

The NRC issued 17 generic communication documents (including supplements) involving boric acid leakage or corrosion caused by boric acid deposits during the period 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) 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.

E.3.1 Generic Communications Issued between 1980 and First Quarter 2002

Table E.3-1, “NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002,” provides operating experience information relevant to boric acid leakage and corrosion.

Table E.3-1. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002

Generic Com	Title	Issue Date	Abstract	NRC Information Requests
IN 80-27	Degradation of Reactor Coolant Pump Studs	6/11/80	Corrosion damage to a number of closure studs in two of the four Byron Jackson RCPs at Fort Calhoun (FTC). Cause of the wastage is thought to be corrosive attack by hot boric acid from the primary coolant. The condition of the studs discovered at FTC raises concerns that such severe corrosion, if undetected, could led to stud failures which could result in loss of integrity of the reactor coolant pressure boundary. The lack of effectiveness of current UTs in revealing wastage emphasizes the need for supplemental visual inspections and use of instrumented leak detection systems to preclude unacceptable stud degradation going undetected. Licensees should consider that the potential for undetected wastage of carbon steel bolting by a similar mechanism could exist in other components such as valves.	None required.
IN 82-06	Failure of Steam Generator Primary Side Manway Closure Studs	3/12/82	At Maine Yankee, 6 of 20 manway closure studs failed an another 5 were found by UT to be cracked. Boric acid from a small leak was the cause. Reference was made to similar events at Calvert Cliffs, FTC, Oconee, and ANO-1.	None required.
BL 82-02	Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants	6/2/82	Recaps the FTC and Maine Yankee bolting problems in IN 80-27 and IN 82-06. Adds that certain lubricants may promote stress corrosion cracking. At the present time, visual examination (e.g., IWA 2210, VT, VT-1) appears to be the only method to detect borated water corrosion wastage or erosion-corrosion 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 threaded fasteners practices. 2. Threaded fasteners of closure connections, identified in the scope of this bulletin, when opened for component inspection or maintenance 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 RCP B that have experienced leakage, particularly those locations where leakage occurred during the most recent plant operating cycle. Describe the inspections made and corrective measures taken to eliminate the problem. If the leakage was attributed to gasket failure or its design, so indicate. 3b. Identify those closures and connections, if any, where fastener lubricants and injection sealant materials have been or are being used and report on plant experience with their application particularly any instances of SCC of fasteners. 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. (4a) A statement that Action Item 1 has been completed. (4b) Identification of the specific connections examined as required by Action Item 2. (4c) The results of examinations performed on the threaded fasteners as required by Action Item 2. If no degradation was observed for a particular connection, a statement to that effect, identification of the connection and, whether the fasteners were examined in place or removed is all that is required. If degradation was observed, the report should provide detailed information. 5. A written report to the Regional office within 60 days of the date of this bulletin. The report is to provide the information requested by Action Item 3.

Table E.3-1. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002 (Continued)

Generic Com	Title	Issue Date	Abstract	NRC Information Requests
IN 86-108	Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion	12/29/86	Alert recipients of a severe instance of boric acid induced corrosion of ferritic steel components in the reactor coolant system. In October 1986, ANO-1 discovered the wastage of the exterior of the HPI nozzle and some wastage of the RCS cold leg pipe (upon removal of insulation). Leakage of RCS from a leaking HPI valve which was above the nozzle and pipe. The corrosion was approximately 1/4 inch deep. Boric acid corrosion has been found to be most active where the metal surface is cool enough so that it is wetted. If the metal is sufficiently hot, then the surface will stay dry and this loss of electrolyte will slow the corrosion rate.. Boric acid corrosion rates in excess of 1 inch depth per year in ferritic steels have been experienced in plants and duplicated in laboratory tests where low quality steam from borated reactor coolant impinged upon a surface and kept it wetted.	None required.
IN 86-108 Sup #1	Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion	4/20/87	On 3/13/87, Turkey Pt. 4 discovered more than 500 # of boric acid crystals on the RV head. There also was a large amount of boric acid crystals in the exhaust cooling ducts for the control rod drive mechanisms. After removal of this boric acid and steam cleaning of the RV head, severe corrosion of various components on the RV head was noted. This event has once again demonstrated that boric acid will rapidly corrode ferritic 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. On 3/13/87, 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. Reference was made to experience in Europe for a PWR in 1970 which experienced high corrosion rates for boric acid induced corrosion. Three RV head bolts, the CRDM cooling shroud were replaced because of corrosion.	None required.

Table E.3-1. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002 (Continued)

Generic Com	Title	Issue Date	Abstract	NRC Information Requests
IN 86-108 Sup #2	Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion	11/19/87	Two events are presented: Following shutdown of Salem 2 on 8/7/87, inspection teams entered containment building to look for reactor coolant leaks that would account for the increased radioactivity in containment air that was noted before the shutdown. Boric acid crystals were found on a 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 leak was the thermocouple instrumentation pinhole leaks. Nine corrosion pits in the vessel head were found. The pits were 1 to 3 inches in diameter and 0.4 to 0.36 inches deep. While attempting to open a shutdown cooling valve at San Onofre 2 on 8/31/87, the packing area came apart (fasteners corroded by boric acid) and eventually dumped 18,000 gallons of reactor coolant in to the containment. Westinghouse reported that boric acid corrosion rates are greater than those that were either previously known or estimated.	None required.

Table E.3-1. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002 (Continued)

Generic Com	Title	Issue Date	Abstract	NRC Information Requests
IN 86-108 Supplement 3	Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion	1/5/95	Presents two additional events involving boric acid corrosion: Calvert Cliffs 1 (2/94), and TMI1 (3/7/94). In 2/94, Calvert Cliffs 1 (CC1) found three nuts on an incore instrumentation flange that were corroded by boric acid, resulting in a leak. During a subsequent inspection, three more nuts on another incore instrumentation flange were also corroded by the same mechanism. On 3/7/94, and while a 100 % power, TMI1 was trying to eliminate a leak of a pressurizer spray valve by tightening a bonnet stud, when the leak suddenly increased to 3 gpm. Other studs completely failed. CC1 thought that the corrosion rate from the leakage was acceptably low in 6/93, and elected to defer the corrective actions for the flanges until the 1994 refueling outage. Other parts of the IN recap earlier problems with boric acid corrosion.	None required.
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 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 Pt. 4, Salem 2, San Onofre 2, ANO-1 and FTC. The GL cites BL 82-2 as not requiring the licensees to institute a systematic program for monitoring small primary coolant leakages and to perform maintenance before leakages could cause significant corrosion damage. Because of this deficiency in the BL, the GL requests 4 actions to be taken by licensees.	(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.

Table E.3-1. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002 (Continued)

Generic Com	Title	Issue Date	Abstract	NRC Information Requests
IN 90-10	Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600	2/23/90	Alert licensees to potential problems related to PWSCC of Inconel 600 that has occurred in pressurizer heater thermal sleeve and instrument nozzles at several domestic and foreign PWR plants. During the 1989 refueling outage at CC2, 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 INCO. All instrument nozzles were made from heat no. NX8297. On 2/27/86 a small leak was observed on a 3/4 inch 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 Inconel 600 applications 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 within about 0.125 inch of the outside surface of the pump (2.5 inches long by 1.5 inches wide by 0.5 inches deep).	None required.

Table E.3-1. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002 (Continued)

Generic Com	Title	Issue Date	Abstract	NRC Information Requests
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 at a French plant (Bugey 3), an NRC action plan was implemented to address PWSCC at all U. S. plants. The NRC asked the Nuclear Management and Resources Council (NEI) to coordinate future industry actions because the issue was applicable to all PWRs. Each owners group submitted individual safety assessments, dated February 1993, through NEI to the NRC on the CRDM cracking issue. In July 1993, the NEI submitted to the NRC proposed acceptance criteria for flaws identified during inservice examination of CRDM penetrations. On the basis of owners group analyses and the European experience, the NRC concluded that there was a high probability that CRDM penetrations at U.S. plants may contain 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. 16 of 17 spare penetrations showed stress corrosion cracking, and 4 of 20 active penetrations showed stress corrosion cracking.	None required.

Table E.3-1. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002 (Continued)

Generic Com	Title	Issue Date	Abstract	NRC Information Requests
GL 97-01	Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations	4/1/97	This GL requests licensees (1) to describe their program for ensuring the timely inspection of PWR control rod drive mechanism and other vessel closure head penetrations and (2) require that all addresses provide to the NRC a written response to the requested information. Beginning in 1986, leaks have been reported in several Alloy 600 pressurizer instrument nozzles at both domestic and foreign reactors from several different NSSS vendors. In 1989, PWSCC was an emerging technical issue, after cracking was noted in Alloy 600 pressurizer heater sleeve penetrations at a domestic facility. The NRC staff determined that the cracking was not of immediate safety significance because the cracks were axial, had a low growth rate, were in a material with an extremely high flaw tolerance (high fracture toughness) and, accordingly, were unlikely to propagate very far. These factors also demonstrated that any cracking would result in detectable leakage and the opportunity to take corrective action before a penetration would fail. European and Japanese utilities have taken steps to detect and mitigate the PWSCC damage and to detect the leakage at an early stage. European and Japanese utilities have inspected most of the CRDM nozzles and repaired the nozzles or replaced the vessel heads as appropriate. In Japan, the three most susceptible vessel heads are being replaced, even though no cracks were found in the nozzles of these heads. In France, Electricite de France (EDF) is planning on replacing all vessel heads as a preventative measure. Removable insulation on the vessel head and leakage monitoring systems are installed at French and Swedish plants for early detection of leakage. The NRC staff concluded that VH penetration cracking does not pose an immediate or near term safety concern. A 11/19/93 NRC safety evaluation is referenced which states that the staff recommends that NUMARC (NEI) consider 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. The staff believes that it is prudent for NUMARC (NEI) to consider the implementation of an enhanced leakage detection method for detecting small leaks during plant operation. On 3/5/96, NEI submitted a white paper entitled “Alloy 600 RPV Head Penetration	Regarding inspection activities: 1.1 A description of all inspections of CRDM nozzle and other VH penetrations performed to the date of this generic letter, including the results of these inspections. 1.2 If a plan has been developed to periodically inspect the CRDM nozzle and other VH penetrations, a) provide the schedule for first, and subsequent, inspections of the CRDM nozzle and other VH penetrations, including the technical basis for this schedule, b) provide the scope for the CRDM nozzle and other VH penetration inspections, including the total number of penetrations (and how many will be inspected), which penetrations have thermal sleeves, which are spares, and which are instrument or other penetrations. 1.3 If a plan has not been developed to periodically inspect the CRDM nozzle and other VH penetrations described above, provide the analysis that supports the selected course of action as listed in either 1.2 or 1.3 above. In particular, provide a description of all relevant data and/or tests used to develop crack initiation and crack growth models, the methods and data used to validate these models, the plant-specific inputs to these models, and how these models substantiate the susceptibility evaluation. Also, if an integrated industry inspection program is being relied on, provide a detailed description of this program. 2. Provide a description of any resin bead intrusions, as described in IN 96-11, that have exceeded the current EPRI PWR Primary Water Chemistry Guidelines recommendations for primary water sulfate levels, including the following information: 2.1 Were the intrusions cation, anion, or mixed bed? 2.2 What were the durations of these intrusions? 2.3 Does the plant’s RCS water chemistry Technical Specifications follow the EPRI guidelines? 2.4 Identify any RCS chemistry excursions that exceed the plant administrative limits for the following species: sulfates, chlorides or fluorides, oxygen, boron, and lithium. 2.5 Identify any conductivity excursions which may be indicative of resin intrusions. Provide a technical assessment of each excursion and any followup actions. Respond within 30 days. 2.6 Provide an assessment of the potential for any of these intrusions to result in a significant increase in the probability for IGA for VH penetrations an any associated plan for inspections.

Table E.3-1. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002 (Continued)

Generic Com	Title	Issue Date	Abstract	NRC Information Requests
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	Alert licensees to the recent detection of through-wall circumferential cracks in two of the control rod drive mechanism penetration nozzles and weldments at the Oconee Nuclear Station, Unit 3. The circumferential crack in the #56 CRDM nozzle was through-wall, and the #50 nozzle had pin hole through-wall indications. These cracks followed the weld profile contour, and were nearly 165 degrees in length. Root cause of the cracking was PWSCC. The nozzles were shrink fit by cooling to at least minus 140 degrees F, inserted into the closure head penetration, and then allowed to warm to room temperature (70 degrees F minimum). The CRDM nozzles were tack-welded and then permanently welded to the closure head using 182-weld metal. The recent identification of significant circumferential cracking of two CRDM nozzles at Oconee 3 raises concerns about a potentially risk-significant condition affecting all domestic PWRs. Further, the environment in the CRDM housing annulus will likely be far more aggressive after any through-wall leakage, because potentially highly concentrated borated primary water will become oxygenated, increasing crack growth rates. The Oconee 3 cracking reinforces the importance of examining the upper PWR RPV head area (e.g., visual under-the-insulation examinations of the penetrations for evidence of borated water leakage or volumetric examinations of the CRDM nozzles) and of using appropriate NDE methods to adequately characterize cracks.	None required.

Table E.3-1. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002 (Continued)

Generic Com	Title	Issue Date	Abstract	NRC Information Requests
BL 2001-01	Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles	8/3/01	The purpose of the bulletin is to request that addresses provide information related to the structural integrity of the reactor pressure vessel head penetration nozzles for their respective facilities, including the extent of VHP nozzle leakage and cracking that has been found to date, the inspections and repairs that have been undertaken to satisfy applicable regulatory requirements, and the basis for concluding that their plans for future inspections will ensure compliance with applicable regulatory requirements, and require that all addresses provide to the NRC a written response. The Bulletin recaps thru-wall circumferential cracking experienced at Oconee 3. As a remedial measure, the RPV head may have to be cleaned at a prior outage for effective identification of new deposits from VH penetration nozzle cracking if new deposits cannot be discriminated from existing deposits from other sources. The recently identified CRDM nozzle degradation phenomena raise several issues regarding the resolution approach taken in GL 97-01: 1) Cracking of Alloy 182 weld metal has been identified in CRDM nozzle J-groove welds for the first time. The finding raises an issue regarding the adequacy of cracking susceptibility models based only on the base metal conditions. 2) Cracking at ANO 1 raises an issue regarding the adequacy of the industry's GL 97-01 susceptibility model. 3) Circumferential cracking of CRDM nozzles, located outside of any structural retaining welds, has been identified for the first time. This concern raises concerns about the potential for rapidly propagating failure of CRDM nozzles and control rod ejection, causing a loss of coolant accident. 4) Circumferential cracking from the CRDM nozzle OD to the ID has been identified for the first time. This finding raises concerns about increased consequences of secondary effect of leakage from relatively benign axial cracks, 5) Circumferential cracking of CRDM nozzles was identified by the presence of relatively small amounts of boric acid deposits. This finding increases the need for more effective inspection methods to detect the presence of degradation in CRDM nozzles before the nozzle integrity is compromised. The Bulletin cites several GDC criteria (14, 31, 32),10CFR50.55a, and Appendix B, Criteria V, IX, and XVI that may not be fully adhered to.	Requests the following: 1. All addressees: 1a) the plant-specific susceptibility ranking using the PWSCC susceptibility model described in Appendix B to the MRP-44, Part 2 report, 1b) a description of the VH penetration nozzles, including the number type, inside and outside diameter, materials of construction, and the minimum distance between VH penetration nozzles, 1c) a description of the RPV head insulation type and configuration, 1d) a description of the VH penetration nozzle and RPV head inspections (type, scope, qualification requirement, ad acceptance criteria) that have been performed in the past 4 years, and the findings. Include a description of any limitations (insulation or other impediments) to accessibility of the bare metal of the RPV head for visual examinations. 2. If your plant has previously experienced either leakage from or cracking in VH penetration nozzles, provide the following: 2a) a description of the extent of VH penetration leakage and cracking, including the number, location, size and nature of each crack detected, 2b) a description of the additional or supplemental inspections (type, scope, qualification requirements, and acceptance criteria), repairs and other corrective actions you have taken in response to identified cracking to satisfy applicable regulatory requirements, 2c) plans for future inspections (type, scope, qualification requirements, and acceptance criteria) and the schedule, 2d) basis for concluding that the inspections identified in 2c will assure that regulatory requirements are met. Include the following: 2d(1) If your future inspections plans do not include performing inspections before 12/31/01, provide your basis for concluding that the regulatory requirements will continue to be met until the inspections are performed, 2d(2) If your future inspection plans do not include volumetric examination of all VH penetration nozzles, provide your basis for concluding that the regulatory requirements will be satisfied, 3) If the susceptibility ranking for your plant is within 5 EFPY of ONS3, addresses are requested to provide the following: 3a) plans for future inspections and the schedule, 3b) basis for concluding that the inspections identified in 3a will assure that regulatory requirements are met. Include the following specific information: 3b(1) If your future inspection plans do not include performing inspections before 12/31/01, provide your basis for concluding that the regulatory requirements will continue to be met until the inspections are performed, 3b(2) If your future inspection plans include only visual inspections, discuss the corrective actions that will be taken, including alternative inspection methods if leakage is detected. 4. If the susceptibility ranking for your plant is greater than 5 EFPY and less than 30 EFPY of ONS3, addressees are requested to provide the following: 4a) plans for future inspections and schedule, 4b) basis for concluding that the inspections identified in 4a will assure that regulatory requirements are met. Include the following specific information : 4b(1) If your future inspection plans to not include a qualified visual examination at the net scheduled refueling outage, provide your basis for concluding that the regulatory requirements will continue to be met until the inspections are performed, 4b(2) Corrective actions that will be taken, including alternative inspection methods if leakage is detected. 5) Addressees are requested to provide the following information within 30 days after plant restart following the next refueling outage: 5a) a description of the extent of VH penetration nozzle leakage and cracking detected at your plant, including the number, location size, and nature of each crack detected, 5b) if cracking is identified, a description of the inspections, repairs, and other corrective actions you have taken to satisfy applicable regulatory requirements. This information is requested only if there are any changes from prior information submitted.

Table E.3-1. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002 (Continued)

Generic Com	Title	Issue Date	Abstract	NRC Information Requests
IN 2002-11	Recent Experience with Degradation of Reactor Pressure Vessel Head	3/12/02	To inform addressees about findings from recent inspections and examinations of the reactor pressure vessel head at Davis-Besse Nuclear Power Station. Recaps previous generic communication information about boric acid on the RPV head at Davis-Besse. Visual inspections in 1998 showed an even layer of boric acid deposits scattered over the RPV head (including deposits near CRDM nozzle 3). This indicated to the licensee that the boric acid evident on the head flowed downward from leakage in the CRDM flanges. During a refueling outage in 2000, the licensee also performed visual inspections of the CRDM flanges and nozzles. Above the RPV head insulation, those inspections revealed five CRDM flanges with evidence of leakage, including one flange that was the principal leakage point. All of the leaking flanges were repaired by replacing their gaskets. Visual inspections performed below the RPV head insulation during the 2000 refueling outage indicated some accumulation of boric acid deposits on the RPV head. No visible evidence of CRDM nozzle leakage (i.e. leakage from the gap between the nozzle and the RPV head) was detected. The licensee described that the RPV head area was cleaned with demineralized water to the greatest extent possible, while trying to maintain the dose as low as reasonably achievable (ALARA). Subsequent video inspection of the partially cleaned RPV head and nozzles was performed for future reference. A subsequent review of the 1998 and 2000 inspection video tapes in 2001 confirmed that there was no evidence of leakage from the RPV head nozzles, although many areas of the RPV head were not accessible because of persistent boric acid deposits that the licensee did not clean because of ALARA issues (including the region around nozzle 3). The inspections in 2002 did not reveal any visual evidence of flange leakage from above the RPV head. However, three CRDM nozzles had indications of cracking (identified by ultrasonic testing of the nozzles), which could result in leakage from the RPV to the top of the RPV head.	None required.

Table E.3-1. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002 (Continued)

Generic Com	Title	Issue Date	Abstract	NRC Information Requests
BL 2002-01	Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity	3/18/02	The purpose of the bulletin is to require PWR addressees to submit (1) information related to the integrity of the reactor pressure boundary including reactor pressure vessel head and the extent to which inspections have been undertaken to satisfy applicable regulatory requirements, and (2) the basis for concluding that plants satisfy applicable regulatory requirements related to the structural integrity of the reactor coolant pressure boundary and future inspections will ensure continued compliance with applicable regulatory requirements, and (3) a written response to the NRC if they are unable to provide the information or they can not meet the requested completion dates. Recaps past generic communications and experience at Davis-Besse. A past model where boric acid crystals are assumed to accumulate on the RPV head, the deposits were assumed to cause minimal corrosion while the reactor was operating because the temperature of the RPV head is above 500 F during operation, and dry boric acid crystals are not very corrosive. Therefore, wastage was typically expected to occur only during outages when the boric acid could be in solution, such as when the temperature of the RPV head falls below 212 F. These findings at Davis-Besse bring into question the reliability of this model. Inspections performed to date at plants with high and moderate susceptibility have generally confirmed the ability of the model to predict a plant's relative susceptibilities, however, a plant with a ranking of 14.3 effective full-power years from the Oconee 3 condition (at the time when circumferential cracking was identified at Oconee 3 in March 2001) identified three nozzles with cracking, other plants with fewer effective full-power years from the Oconee 3 condition did not identify cracking. Some inspection and repair methods may not have been capable of identifying the presence of a void in the carbon steel head adjacent to the cladding interface.	1. Within 15 days of the date of the bulletin, all PWR addressees are required to provide the following: A) a summary of the reactor pressure vessel head inspection and maintenance programs that have been implemented at their plants, B) an evaluation of the ability of their inspection and maintenance programs to identify degradation of the RPV head including, thinning, pitting, or other forms of degradation such as the degradation of the RPV observed at Davis-Besse, C) a description of any conditions identified (chemical deposits, head degradation) through the inspection and maintenance programs described in 1A that could have led to degradation and the corrective actions taken to address such conditions, D) schedule, plans, and basis for future inspections of the RPV head and penetration nozzles. This should include the inspection method(s), scope, frequency, qualification requirements, and acceptance criteria, and E) conclusions regarding whether there is reasonable assurance that regulatory requirements are currently being met. If the evaluation does not support the conclusion that there is reasonable assurance that regulatory requirements are being met, discuss plans for plant shutdown and inspection. If the evaluation supports the conclusion that there is reasonable assurance that regulatory requirements are being met, provide your basis for concluding that all regulatory requirements will continue to be met until the inspections are performed. 2. Within 30 days after plant restart following the next inspection of the RPV head to identify any degradation, all PWR addressees are required to submit to the NRC the following information: A) the inspection scope and results, including the location, size, and nature of any degradation detected, and B) the corrective actions taken and the root cause of the degradation. 3. Within 60 days of the date of this bulletin, all PWR addressees are required to submit to the NRC the following information related to the remainder of the reactor coolant pressure boundary: A) the basis for concluding that their boric acid inspection program is providing reasonable assurance of compliance with the applicable regulatory requirements discussed in Generic Letter 88-05 and this bulletin. If a documented basis does not exist, provide your plans, if any for a review of your programs. Within 7 days of the date of the bulletin, a PWR addressee is required to submit a written response if they re unable to provide the information or they can not meet the requested completion dates. Alternative courses of action and their basis must be provided.

Table E.3-1. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002 (Continued)

Generic Com	Title	Issue Date	Abstract	NRC Information Requests
IN 2002-13	Possible Indicators of Ongoing Reactor Pressure Vessel Head Degradation	4/4/02	To alert addressees to possible indicators of RPV boundary degradation including degradation of the RPV head material. These indicators include unidentified reactor coolant system leakage and containment air cooler and radiation element filter fouling. Containment air coolers cleaning of boron deposits greatly increased. The licensee noticed that deposits removed from CAC 1 exhibited a rust-like color. The licensee attributed the discoloration to migration of the surface corrosion on the CACs into the boric acid deposits and to the aging of the boric acid deposits. During the 2002 outage, fifteen 5-gallon buckets of boric acid were removed from the CAC ductwork and plenum A flow from the CACs also resulted in boric acid deposits elsewhere within containment including on service water piping, stairwells, and other areas of low ventilation. The radiation element filters accumulate particulates and may need to be changed to ensure acceptable system operation. Licensee records correlate RE filter changes with past RCS leakage increases. In March 1999, RE filter clogging from boric acid deposits was identified and attributed to the pressurizer relief valve modification. In November 1999, after identifying yellowish brown deposits in the filters, the licensee obtained a chemical analysis of the filter particulates which identified the presence of ferric oxide in addition to boric acid crystals. Around that time, the licensee began changing the filters every one-to-three weeks. By November 1999, the frequency of filter changes had again increased.	None required.

E.3.2 Operating Experience Events and Issuance of NRC Generic Communications

Figure E.3-1, "Boric Acid Leakage and Corrosion Events Versus Relevant NRC Generic Communication Documents," shows that several years elapsed (with relatively high numbers of primary system leakage or boric acid corrosion events) during which the NRC did not issue any generic communications related to boric acid leakage or corrosion. For example, during the period from 1989 through 1994, the NRC issued two INs (IN 90-10 on PWSCC of Alloy 600, and IN 94-63 on boric acid corrosion of a pump casing). In addition, during the period from 1998 through 2000, plants experienced instances of RCS nozzle leakage without the NRC issuing any related generic communication.

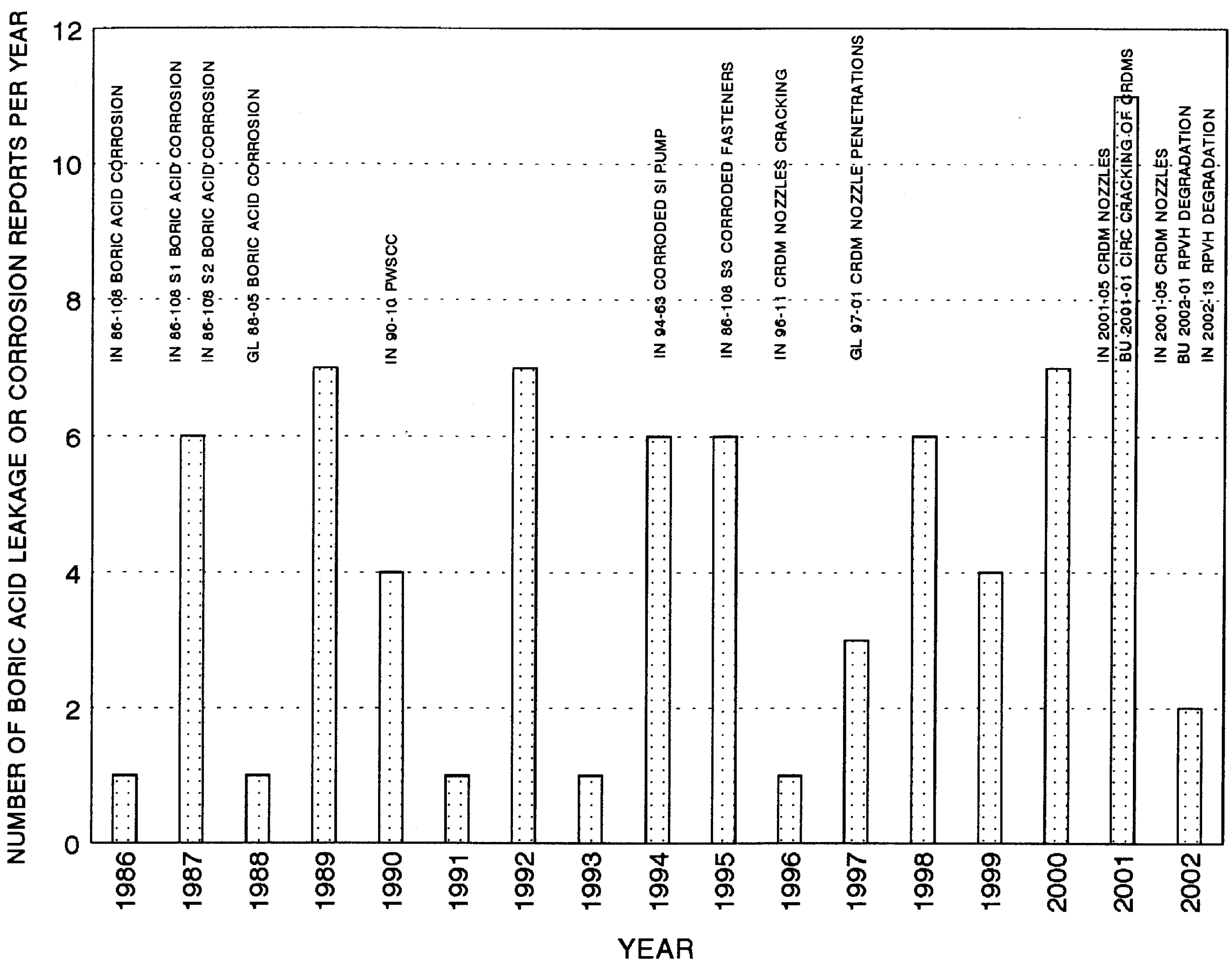


Figure E.3-1. Boric Acid Leakage and Corrosion Events Versus Relevant NRC Generic Communication Documents

E.3.2.1 Boric Acid Leakage or Corrosion Events Reported from 1989 Through 1994 That Did Not Result in a Generic Communication

(1) McGuire Unit 1 (LER #36989020). On July 27, 1989, 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.

(2) Catawba Unit 1 (LER #41389020). On September 21, 1989, a preliminary visual inspection of the Catawba Units 1 and 2 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.

(3) Arkansas Nuclear One Unit 1 (LER #31389043). On December 8, 1989, while removing the nut ring from beneath the reactor vessel nozzle flange at 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.

(4) Millstone Unit 3 (LER #42389031). On November 28, 1989, a loose nozzle ring set screw on the 'C' PZR 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.

(5) 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.

(6) 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.

(7) Waterford Unit 3 (LER #38292006). On July 11, 1992, an Unusual Event was declared as a result of RCS 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.

(8) Seabrook Unit 1 (LER #44392026). On July 14, 1992, it was discovered that three of the four cover bolts on Chemical Volume Control System 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.

(9) Millstone Unit 3 (LER #42394012). On September 9,1994, a leak was discovered in 3/4-inch socket weld on a 'C' 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.

(10) 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.

(11) Three Mile Island Unit 1 (LER #28994001). On March 7, 1994, TMI-1 located and isolated a body-to-bonnet leak from the PZR spray valve (RC-V1). The root causes was boric acid degradation of 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.

(12) 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.

(13) Calvert Cliffs Unit 2 (LER #31894003). On July 11, 1994, a non-isolable RCS 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.

(14) Oconee Unit 3 (LER #28791008). On November 23, 1991, the operators received several alarms 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 reactor building.

(15) Surry Unit 2 (LER #28192008). On December 15, 1992, an 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 fitting.

(16) Arkansas Nuclear One Unit 1 (LER #31390021). On December 22, 1990, a potential RCS leak in the area of a PZR 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 PZR shell and breached the outside diameter of the nozzle at the toe of the nozzle to vessel weld.

(17) Ft. Calhoun Unit 1 (LER #28590028). On December 14, 1990, an investigation of unknown 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.

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

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

(20) San Onofre Unit 2 (LER #36192004). On February 18, 1992, a dye-penetrant examination of a PZR 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 RCS 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 PWSCC of the Inconel 600 material.

(21) Palisades Unit 1 (LER #25593011). On October 9, 1993, an inspection of the PZR 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 PWSCC of the Inconel 600 nozzle material.

(22) St. Lucie Unit 2 (LER #38994002). On March 16, 1994, Florida Power and Light (FPL) Engineering personnel identified trace amounts of boric acid on the exterior of the PZR 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 PZR.

(23) 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 PWSCC of alloy 600 material at the instrument nozzle.

E.3.2.2 Boric Acid Leakage or Corrosion Events Reported From 1998 Through 2000 That Did Not Result in a Generic Communication

(1) Davis-Besse Unit 1 (LER #34698009). On September 9, 1998, two of the eight body to bonnet nuts missing on Reactor Coolant PZR 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 separation work practices during previous maintenance activities. These nuts were subsequently replaced on September 9-10, 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.

(2) 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 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.

(3) Salem Unit 2 (LER #31198007). On July 29, 1998, indications of leakage through 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 PZR 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.

(4) 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 1 Containment Spray header and residual heat removal (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.

(5) 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 connection. A sample of the water revealed that the water was from the RCS, indicating a through wall leak of the thermowell.

(6) Palo Verde Unit 1 (LER #52899006). On October 2,1999, a small accumulation of boric acid residue was discovered on an RCS 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.

(7) 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.

(8) Waterford Unit 3 (LER #38299002). On February 25, 1999, RCS pressure boundary leakage involving two Inconel 600 instrument nozzles on the top head of the PZR was discovered. Subsequent inspections of the remainder of Inconel 600 nozzles identified 3 more leaking nozzles. One is on RCS hot leg #1 resistance temperature detector (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 of the nozzle partial penetration welds resulting from PWSCC. The leaking PZR 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).

(9) 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, liquid penetrant (PT), and eddy current 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.

(10) Arkansas Nuclear One Unit 2 (LER #36800001). On July 30, 2000, twelve PZR 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.

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

(12) Waterford Unit 3 (LER #38200011). On October 17, 2000 evidence of leakage was discovered on a PZR heater sleeve. 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.

(13) Arkansas Nuclear One Unit 1 (LER #31300003). On February 15, 2000, a weld in a 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 PWSCC.

(14) Summer Unit 1 (LER #39500008). On October 7, 2000, an accumulation of boric acid near the "A" loop of the RPV 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 ultrasonic 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.

(15) Oconee Unit 1 (LER #26900006). On November 25, 2000, small amounts of boric acid was found on the top surface of the RPV head. The deposits appeared to be located at the base of 5 (of the 8) unused thermocouple (T/C) 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 inside diameter of the nozzles in the vicinity of the partial penetration weld (on the underside of the RPV head). On December 9, 2000, a PT 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.

E.4.0 REPORTED EVENTS INVOLVING PRIMARY SYSTEM LEAKAGE OR BORIC ACID CORROSION

Plants reporting primary system leakage or boric acid corrosion are listed below in alphabetical order. The LER number, if issued, is given in the parenthesis.

(1) Arkansas Nuclear One, Unit 1 (LER #31386006), October 23, 1986, Corrosion was discovered on a RCS nozzle and an adjacent cold leg.

(2) Arkansas Nuclear One, Unit 1 (LER #31389043), December 8, 1989, Control rod drive mechanism nut ring halves had corroded approximately 50% and that two of the four bolt holes in the corroded nut ring half were degraded.

(3) Arkansas Nuclear One, Unit 1 (31390021), February 22, 1990, RCS leak was discovered in the area of a PZR upper level instrumentation nozzle.

(4) Arkansas Nuclear One, Unit 1 (LER #31300003), February 15, 2000, An RCS hot leg level instrumentation nozzle was found to have been leaking as indicated by boron buildup.

(5) Arkansas Nuclear One, Unit 1 (LER #31301002), March 24, 2001, Indication of boric acid crystals were noted in the area of one CRDM nozzle on the RPV.

(6) Arkansas Nuclear One, Unit 2, (LER #36887003), April 24, 1987, PZR heaters had ruptured resulting in damage to the heater sleeves, causing boric acid induced corrosion damage to the PZR carbon steel base metal.

(7) Arkansas Nuclear One, Unit 2 (LER #36800001), July 30, 2000, Twelve PZR heater sleeves and one RCS hot leg resistance temperature detector nozzle were leaking.

(8) Beaver Valley, Unit 2 (LER #41200003), February 11, 2000, RCS leakage into the containment building was attributed to an abrupt packing leak on a motor-operated drain insolation valve on the RCS.

(9) Calvert Cliffs, Unit 1 (LER #31794004), February 21, 1994, Higher than anticipated corrosion of three nuts was found on one of the incore instrumentation flanges on the Unit 1 RPV head.

(10) Calvert Cliffs, Unit 1 (LER #31794003), March 21, 1994, PZR heater sleeves were found to be leaking.

(11) Calvert Cliffs, Unit 2 (LER #31889007), May 5, 1989, Reactor coolant leakage was found from 28 of the 120 PZR vessel heater penetrations and one upper level nozzle.

(12) Calvert Cliffs, Unit 2 (LER #31894003), July 11, 1994, Leak was caused by a 150 degree circumferential crack in a weld in the 22A Safety Injection Tank discharge test connection.

(13) Catawba, Unit 1 (LER #41389020), September 21, 1989, Catawba Units 1 and 2 steel containment vessel exterior surfaces were found to be corroded by boric acid.

(14) Catawba, Unit 2 (LER #41401002), September 19, 2001, Steam generator 2B lower head bowl drain indicated boron residue buildup.

(15) Cook, Unit 1 (LER #31598027), May 5, 1998, Boric acid deposits/blockage were discovered in the Unit 1 RHR spray piping.

(16) Crystal River, Unit 3 (LER #30201004), October 1, 2001, CRDM nozzle #32 was leaking from two axially oriented cracks that were through-wall.

(17) Davis-Besse, Unit 1 (LER #34698009), September 9, 1998, Boric acid leak and corrosion of three fasteners of the PZR spray valve were discovered.

(18) Davis-Besse, Unit 1 (LER #34602002), February 27, 2002, CRDM nozzles revealed axial indications and leakage on nozzles #1, 2, and 3, including severe RPV head wastage from boric acid buildup.

(19) Diablo Canyon, Unit 1 (LER #27588004), February 25, 1988, Leaks in canopy seal welds of the CRDM head adapter plugs were discovered.

(20) Diablo Canyon, Unit 1 (LER #27590010), July 26, 1990, Leakage through a crack in the positive displacement charging pump suction piping elbow was discovered.

(21) Diablo Canyon, Unit 2 (LER #32387023), October 9, 1987, Leaks in Unit 1 and 2 accumulator nozzles were discovered.

(22) Ft. Calhoun, Unit 1 (LER #28590028), December 14, 1990, RCS leakage on spare CRDM housings were discovered.

(23) Ft. Calhoun, Unit 1 (LER #28592018), March 20, 1992, Severe corrosion of the carbon steel fasteners on the boric acid pump flanges and piping supports were discovered.

(24) Haddam Neck, Unit 1 (LER #21396019), August 31, 1996, Pinhole leak in the body of an eight inch inlet isolation valve (RH-V-791A) to the 'A' RHR heat exchanger was discovered.

(25) Maine Yankee, Unit 1 (LER #30995013), October 16, 1995, Seven of eight bonnet retention cap screws parted during attempts to remove them due to boric acid corrosion of the High Pressure Safety Injection Loop 2 Stop valve.

(26) McGuire, Unit 1 (LER #36989020), July 27, 1989, Abnormal degradation of Unit 1 and 2 steel containment vessels was caused by boric acid corrosion.

(27) Millstone, Unit 2 (LER #33695023), May 16, 1995, Indications on boric acid section of the Chemical and Volume Control System fittings and pipe subjected to periodic boric acid leaks over the years from valves.

(28) Millstone, Unit 2 (LER #33602001), February 19, 2002, Two PZR heater sleeve penetrations were leaking as evidenced by boron precipitation build up.

(29) Millstone, Unit 3 (LER #42389031), November 28, 1989, PZR safety valve nozzle ring set screw corroded by boric acid.

(30) Millstone, Unit 3 (LER #42394012), September 9, 1994, A leak was discovered in 3/4-inch socket weld on a 'C' RCS Loop Flow Instrumentation line cause by a circumferential crack approximately, 5/8-inch long.

(31) Millstone, Unit 3 (LER #42395020), December 2, 1995, Leak from the valve stem leak-off pipe for the RHR System.

(32) North Anna, Unit 2 (LER #33901003), November 13, 2001, A through-wall leak on RPV penetration number 63 was identified based on the presence of boric acid was discovered.

(33) Oconee, Unit 1 (LER #26900006), December 4, 2000, Boric acid deposits at 8 unused thermocouple nozzles and one CRDM nozzle were found.

(34) Oconee, Unit 2 (LER #27097001), April 21, 1997, Leak from a crack at the safe end to pipe weld on the High Pressure Injection to RCS cold leg nozzle near Reactor Coolant Pump (RCP).

(35) Oconee, Unit 2 (LER #27001002), April 28, 2001, Multiple leaking CRDM nozzles were discovered.

(36) Oconee, Unit 3 (LER #28791008), November 23, 1991, Leak from a failed fitting on an instrument line at the top of a steam generator resulted in approximately 87,000 gallons of RCS leakage.

(37) Oconee, Unit 3 (LER #28701001), February 18, 2001, Boric acid deposits were identified around nine (Nozzles 3, 7, 11, 23, 28, 34, 50, 56, and 63) of 69 total CRDM nozzles.

(38) Oconee, Unit 3 (LER #28701003), November 12, 2001, Boric acid deposits were discovered at the base of seven CRDM nozzles resulting from axial and circumferential cracks.

(39) Palisades, Unit 1 (LER #25593011), October 9, 1993, PZR upper and lower temperature nozzle penetrations were leaking.

(40) Palisades, Unit 1 (LER #25599004), November 2, 1999, Boric acid deposits on three CRDM seal housings and 30 of the 45 seal housing assemblies contained small circumferential cracks.

(41) Palisades, Unit 1 (LER #25501002), March 31, 2001, Thirteen CRDM seal housings were not returned to service due to NDE indications, confirmed cracks, or mechanical seal performance deficiencies.

(42) Palo Verde, Unit 1 (LER #52899006), October 2, 1999, Boric acid residue was found on an RCS loop 2 hot leg instrument nozzle.

(43) Palo Verde, Unit 1 (LER #52801001), March 31, 2001, Boric acid on an RCS hot let instrument nozzle.

(44) Palo Verde, Unit 2 (LER #52900004), October 4, 2000, Boric acid residue on a RCS PZR heater sleeve.

(45) Point Beach, Unit 1 (LER #26690008), July 20, 1990, Reactor coolant was leaking through a canopy seal weld on CRDM I-3 and the upstream weld on B steam generator channel head drain line isolation valve 1RC-526B.

(46) Point Beach, Unit 1 (LER #26699012), November 4, 1999, A through-wall leak was discovered in valve 1RC-526A, and included boric acid crystals on the weld.

(47) Salem, Unit 2 (No LER), August 7, 1987, 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 CRDM housings.

(48) Salem, Unit 2 (LER #31198007), July 30, 1998, Leakage indications were found on the tubing of six RCS instrument lines and on tubing in the PZR liquid sample line delay coil.

(49) San Onofre, Unit 2 (LER #36192004), February 18, 1992, Rust and boric acid crystals in the vicinity of the PZR vapor space level instrument nozzle were found.

(50) San Onofre, Unit 2 (LER #36198002), January 26, 1998, Leakage from cracks through instrument nozzles were found.

(51) San Onofre, Unit 3 (LER #36295001), July 22, 1995, Leakage from a PZR level instrumentation nozzle and two RCS hot leg instrument nozzles were found.

(52) San Onofre, Unit 3 (LER #36297001), 4/12/1997, Leaking instrument nozzles in RCS were discovered.

(53) San Onofre, Unit 3 (LER #36297002), Jly 3, 1997, Leaking RCS nozzles were discovered.

(54) Seabrook, Unit 1 (LER #44392026), July 14, 1992, Cover bolts had fractured on multiple valves reuslting in leakage.

(55) St. Lucie, Unit 1 (LER #33587014), October 8, 1987, A leaking check valve bonnet and a cracked pipe in the heat affected zone on the 1A1 RCP lower cavity seal nozzle were discovered.

(56) St. Lucie, Unit 1 (LER #33501003), April 14, 2001, A through wall RCS leak on a hot leg instrument nozzle was found.

(57) St. Lucie, Unit 2 (LER #38994002), March 16, 1994, Boric acid was found on the exterior of the PZR steam space instrument nozzles.

(58) St. Lucie, Unit 2 (LER #38995004), October 10, 1995, An instrument nozzle located on the 'B' side RCS hot leg exhibited boric acid buildup.

(59) Summer, Unit 1 (LER #39500008), October 12, 2000, Boron buildup on the weld between the reactor vessel nozzle and the hot leg pipe was discovered.

(60) Surry, Unit 1 (LER #28098006), March 24, 1998, Boric acid build-up was found on the head of the RCP lower radial bearing resistance temperature detector connection.

(61) Surry, Unit 1 (LER #28095007), September 12, 1995, Boron crystals and corrosion products were discovered on the outside diameter of the reactor vessel for two of the four instrument nozzles.

(62) Surry, Unit 2 (LER #28192008), December 15, 1992, RCS leak had developed near the Low Pressure Letdown Flow Transmitter.

(63) Three Mile Island, Unit 1 (LER #28994001), March 7, 1994, A body-to-bonnet leak from PZR spray valve (RC-V1) was caused by boric acid degradation of its fasteners.

(64) Three Mile Island, Unit 1 (LER #28901002), October 12, 2001, Boric acid buildup was found around all eight thermocouple nozzles and boric acid buildup around 12 CRDM nozzles.

(65) Turkey Point, Unit 4 (No LER), March 13, 1987, Boric acid on the RPV head results in severe corrosion of various components in the area.

(66) Waterford, Unit 3 (LER #38292002), March 25, 1992, Packing gland studs on reactor coolant hot leg sample valve failed due to boric acid corrosion.

(67) Waterford, Unit 3 (LER #38292006), July 11, 1992, Packing gland studs on reactor coolant hot leg sample valve failed due to boric acid.

(68) Waterford, Unit 3 (LER #38299002), February 25, 1999, Leakage on PZR instrument nozzles and hot leg nozzles.

(69) Waterford, Unit 3 (LER #38200011), October 17, 2000, Leakage was found at a PZR heater sleeve, including two instances of leakage of two MNSA clamps.

E.5.0 SAMPLE OF DBNPS CORRECTIVE ACTION REPORTS

Table E.5-1, “Boric Acid Leakage, Corrosion, and Control Issues,” provides a representative sample listing of boric acid issues documented at DBNPS since 1989. Problems occurring since 1989 were chosen because most licensees had developed a boric acid corrosion control program by that time in response to GL 88-05.

Table E.5-1. Sample of Boric Acid Leakage, Corrosion, and Control Issues Documented by DBNPS

Report Date	Report Number	Issue
January 1989	PCAQ 1989-0058	Boric acid buildup reported from thermowell leakage near RCP 2-1 and RCP 1-2.
February 1990	PCAQ 1990-0051	Boric acid leak and corrosion discovered in the flange area of the #2 SG handhole.
March 1990	PCAQ 1990-0221	Boric acid leakage from a CRDM flange. Several other flanges are yet to be inspected.
September 1991	PCAQ 1991-0353	Excessive amount of boron was found on the RPV head caused by leaking CRDM flanges.
September 1991	PCAQ 1991-0344	Boric acid leakage coming from SG 1-2(A) (upper manway and lower inspection opening), and SG 1-1(B) (upper and lower inspection openings).
October 1991	PCAQ 1991-0476	Significant boric acid leak coming from the thermowell adjacent to RCP 2-1 cold leg.
February 1992	PCAQ 1992-0072	Containment Air Cooler performance degraded because of boric acid buildup from RCS leakage.
March 1993	PCAQ 1993-0075	Boric acid leakage coming from cold and hot leg thermowells.
March 1993	PCAQ 1993-0098	Boric acid leak and corrosion discovered on SG 1-2(A) head vent flange.
March 1993	PCAQ 1993-0100	Boric acid leak from SG 1-2(A) lower inspection opening and SG 1-1(B) upper and lower inspection openings and the lower manway.
March 1993	PCAQ 1993-0132	Boric acid leakage from 13 CRDM flanges. This has been a repetitive problem since plant startup.
April 1996	PCAQ 1996-0551	Several inches of boron buildup on the RPV head (some boric acid was brown next to CRDM nozzles).
April 1996	PCAQ 1996-0650	Boric acid leakage from pump casing of RCP 1-1.
May 1997	PCAQ 1997-0599	Boric acid buildup at the packing gland area on valve HP 57.

Table E.5-1. Sample of Boric Acid Leakage, Corrosion, and Control Issues Documented by DBNPS (Continued)

Report Date	Report Number	Issue
January 1998	PCAQ 1998-0158	Boric acid leaking from nitrogen supply line to core flood tank isolation valve.
April 1998	PCAQ 1998-0538	Boric acid or mineral deposits were found on the incore tunnel walls and ceiling.
April 1998	PCAQ 1998-0649	Boric acid residue on RPV head caused by leaking CRDM flange.
April 1998	PCAQ 1998-0767	Most of the RPV head was covered with boric acid (some rust brown) including several fist sized clumps. Slight pitting of head was noticed.
April 1998	PCAQ 1998-0824	Boric acid accumulation on the CACs, including corrosion of the carbon steel coil housing of CACs.
May 1998	PCAQ 1998-0915	Pressurizer spray valve yoke (RC2) was severely corroded by boric acid.
May 1998	PCAQ 1998-1130	Boric acid leak at packing for valve RC2.
September 1998	PCAQ 1998-1642	Boric acid corrosion of valve RC2 fasteners.
September 1998	PCAQ 1998-1681	Boric acid leakage and corrosion of valve RC2.
October 1998	PCAQ 1998-1716	Boric acid leakage and corrosion of valve RC2.
October 1998	PCAQ 1998-1885	Excessive boric acid corrosion of fasteners on pressurizer spray valve RC2.
October 1998	PCAQ 1998-1895	Leakage into sump was greater than 1 gpm. The pressurizer spray valve, in addition to other valves, were leaking, but nothing that was significant. DBNPS indicated that they would find the RCS leaks during the midcycle outage in 1999.
November 1998	PCAQ 1998-1965	Boron accumulation on filters for radiation monitors inside containment.
November 1998	PCAQ 1998-1980	Continued boric acid buildup on CACs.
December 1998	PCAQ 1998-2069	Boric acid leakage and corrosion of valve RC2.
December 1998	PCAQ 1998-2071	Service water system piping has a light coating of boric acid from unidentified RCS leakage.
December 1998	CR 1998-0020	Provides a summary of multiple problems with boric acid leakage and corrosion of valve RC2 including corrective actions.

Table E.5-1. Sample of Boric Acid Leakage, Corrosion, and Control Issues Documented by DBNPS (Continued)

Report Date	Report Number	Issue
January 1999	CR 1999-0046	Boric acid leakage from packing on makeup (MU) system valves.
April 1999	CR 1999-0662	Severe boric acid corrosion on service air line in containment.
April 1999	CR 1999-0665	Boric acid buildup on valve RC38.
April 1999	CR 1999-0669	Boric acid buildup on valve CF28.
April 1999	CR 1999-0678	Boric acid buildup on valve RC32.
April 1999	CR 1999-0679	Boric acid buildup on valve RC31.
April 1999	CR 1999-0680	Boric acid buildup on valve HP56.
April 1999	CR 1999-0721	Boric acid leakage, corrosion and wastage of yoke parts of valve RC32.
April 1999	CR 1999-0722	Boric acid leakage, corrosion and wastage of yoke parts of valve RC40.
April 1999	CR 1999-0738	Boric acid leakage, corrosion and wastage of yoke parts of valve RC38.
April 1999	CR 1999-0739	Boric acid leakage, corrosion and wastage of yoke parts of valve MU1A.
May 1999	CR 1999-0745	Boric acid clumps in containment east/west tunnel (Room 181) on the wall. Boric acid entered through overhead grating.
May 1999	CR 1999-0747	Boric acid leakage, corrosion and wastage of yoke and bonnet parts of valve RC50.
May 1999	CR 1999-0748	Boric acid leakage, corrosion and wastage of yoke and parts of valve DH21.
May 1999	CR 1999-0749	Boric acid leakage, corrosion and wastage of yoke parts of valve MU2B.
May 1999	CR 1999-0812	Five to 10% of the cross section of a body to bonnet stud on valve RC33 was intact after it broke. Stud material was reported to be stainless steel.
May 1999	CR 1999-0928	Frequent changing of particulate filter for radiation monitor in containment because of boron buildup.
June 1999	CR 1999-1061	RCS performance measure exceeded when the PORV block valve RC11 was closed to reduce leakage into containment.

Table E.5-1. Sample of Boric Acid Leakage, Corrosion, and Control Issues Documented by DBNPS (Continued)

Report Date	Report Number	Issue
June 1999	CR 1999-1062	RCS performance measure exceeded with unidentified leakage into containment of greater than 0.75 gpm coming from several locations, the largest leakage contributor was thought to be from the pressurizer code safety relief valves.
July 1999	CR 1999-1300	Iron oxide (rust) was found on several containment radiation monitor filters. The source of the rust was unknown. A modification was installed consisting of HEPA filters to reduce particulate concentration.
July 1999	CR 1999-0998	High temperatures inside containment because of CAC fouling caused by boric acid from RCS leakage.
September 1999	CR 1999 1581	Boric crystals and weepage found on the south wall and ceiling in #1 ECCS pump room. Also some buildup on the south wall of room 304, the east wall of cask wash pit and the ceiling in room 109. The condition is worse than in the past.
September 1999	CR 1999-1098	Discusses procedure deficiencies in evaluating unidentified RCS leakage rates and activities.
September 1999	CR 1999-1614	Discusses a commitment completion date that was missed by two days having to do with improvements to the BACC program as a result of lessons learned from the DBNPS RC2 severe boric acid corrosion event in 1998.
November 1999	CR 1999-2061	Repeated computer alarms coming from containment radiation monitors (filter clogging by RCS leakage). Recommended action was to downgrade the monitors to NCAQ and subsequent closure.
April 2000	CR 2000-0699	Steady RCS leakage was reported coming from gasket drain lines for RCPs 1-1, 1-2, and 2-1.
April 2000	CR 2000-0782	Red/brown boric acid leakage from the RPV head weep holes. Preliminary inspection of the head through the weep holes indicated clumps of boric acid present on the east and south sides. The north and west sides have very little boric acid accumulation form the weep holes. Approximately 15 gallons of boric acid had accumulated on the head flange alone.
April 2000	CR 2000-0869	Two inches of boric acid buildup on pump casing and studs for RCP 1-1. Some studs were replaced.
April 2000	CR 2000-0894	Leakage reported from the pump shaft seal o-ring on RCP 1-1.

Table E.5-1. Sample of Boric Acid Leakage, Corrosion, and Control Issues Documented by DBNPS (Continued)

Report Date	Report Number	Issue
April 2000	CR 2000-1037	Inspection of the RPV head indicated large 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 the CRD leakage. There was a high probability that CRDM nozzle #3 was a leaking CRD.
June 2000	CR 2000-1547	Buildup of boric acid on CACs reduces air flow and heat transfer. This condition is repetitive. It was postulated that the majority of the boron plating out on the cooling coils was not due to an active leak, but from residual boron remaining in containment following 12RFO.
June 2000	CR 2000-1630	Boron leaking from the wall on the 555' walkway of the auxiliary building leading to ECCS 1. The buildup of boron has increased since before RFO-12. The boron appears to be causing rust formation on the surrounding structural steel, conduits and hangers.
October 2000	CR 2000-2465	Upon inspection of the internal of several leak detection valves for spent fuel pool wall 4, crystalized boron (rock hard) was found in both the valve internals as well as the piping upstream and downstream of two valves.
November 2000	CR 2000-2809	Boric acid leakage coming from #1 Containment Spray Pump mechanical seal.
November 2000	CR 2000-2875	Recurrent low flow alarms (last 2-3 years) involving containment radiation monitors caused by clogging of their filters by boric acid from RCS leakage.
December 2000	CR 2000-4138	The frequency of cleaning the CACs has increased due to boric acid buildup (most likely originating from the reactor) on the coils. Boron deposits were also found on the walkways on the 565' and 585' levels.
February 2001	CR 2001-0466	Red colored boron deposits were found on a stud on the forward end of #2 Make-Up Pump.
May 2001	CR 2001-1191	This CR identified the need to develop a project plan for addressing potential CRDM J-groove weld cracking issues identified at ANO and Oconee nuclear power plants.
August 2001	CR 2001-2012	Addresses the issuance of NRC Bulletin 2001-01 on circumferential cracking of RPV head penetration nozzles. The CR indicates that a June 2001 DBNPS evaluation determined that there were no related short-term safety issues at Davis-Besse.

Table E.5-1. Sample of Boric Acid Leakage, Corrosion, and Control Issues Documented by DBNPS (Continued)

Report Date	Report Number	Issue
October 2001	CR 2001-2862	This CR extended the due date (from December 2001 to October 2002) for developing an RCS leak identification guidelines. The reason for the extension is that higher priority emergent outage issues have prevented completion.
November 2001	CR 2001-2997	The evaluation of NRC IN 2001-05 was “closed” without being processed, reviewed, approved and distributed in accordance with the DBNPS operational experience program. The operational experience evaluator thought that IN 2001-05 could be closed since the NRC had issued Bulletin 2001-01.
January 2002	CR 2002-00147	Boric acid leakage was noticed coming from a nitrogen supply line to the core flood tank 1-1 check valve.
February 2002	CR 2002-00685	Loose boric acid buildup (1-2" deep) was present around 75% of the circumference of the RPV flange. On the other 25% of the RPV head flange, the boron was hard baked, 3-4" thick. Through wall axial flaws were found in the weld region of CRDM nozzle #3.
February 2002	CR 2002-00846	During performance of the video inspection of the RPV head, more boron than expected was found on the top of the head. Boric acid did not originate from the CRDM flanges, but from CRDM nozzles 3, 2, and 1 (in order of amount of leakage). Additional nozzle cracking issues are included in CR 2002-00891.
March 2002	CR 2002-1107	Long-term boric acid leakage outside TERC3B3/4 thermowell on piping, that may be coming from a seal weld.
March 2002	CR 2002-01159	Potential through wall leak on CRDM nozzle #2. CR 2002-0891 will address CRDM nozzle cracking issues.
March 2002	CR 2002-01378	Boric acid buildup is occurring on components throughout containment. Most of the components affected are either below or in the vicinity of service water piping. In several locations (CAC plenum, service water valve SW392, and JT3952), corrosion is occurring. Corrosion is also occurring on structural steel and conduits, cable trays, flexible conduits and penetrations, and the CAC plenum. Boric acid buildup on valves CF1A and CF9 packing areas. A trail of boric acid was identified at the top of CFT 1-1 which may originate from a hole in the CAC plenum. The potential for boric acid buildup in ventilation ducts needs to be evaluated.

Table E.5-1. Sample of Boric Acid Leakage, Corrosion, and Control Issues Documented by DBNPS (Continued)

Report Date	Report Number	Issue
April 2002	CR 2002-01447	During a containment Mode 5 walkdown, evidence of boric acid streaming (approximately 5 feet wide) was found in the tunnel leading to the fuel transfer tube area from Core Flood Tank Room 1. Approximately 5 gallons of boric acid crystals were present in clumps on the wall and on the floor.
April 2002	CR 2002-01430	Indications of boric acid residue were identified in various location in the reactor cavity area during 12RFO (previous outage). This CR was identified as a Mode Restraint by Operations.
April 2002	CR 2002-01532	Steam cleaners for cleaning (removal of boric acid buildup) the CACs were left inside containment during cycle 12 and 13.
April 2002	CR 2002-01670	Boric acid crystals were discovered adjacent to the west lifting lug on top of the pressurizer.
April 2002	CR 2002-1669	A small amount of corrosion was found around the nozzle of the sample tap of the pressurizer.
April 2002	CR 2002-01690	Corrosion of the underside of the reactor vessel was found, possibly caused by leakage from the upper vessel areas. The heaviest concentration of corrosion was noted around incore guide tube #1 which is the lowest point of the vessel.
May 2002	CR 2002-01820	Boric acid corrosion of major areas of valves DH11 and DH12.
May 2002	CR 2002-01978	Boric acid leakage from flow transmitter FT-MU30D at the high input tap. Beneath the transmitter, approximately 12 square feet of floor area has been contaminated with boric acid.
May 2002	CR 2002-02219	Rust colored boric acid buildup on boric acid pump #1 studs and nuts. The pump flange surface also has boric acid buildup.
May 2002	CR 2002-02294	This CR lists 20 areas of general to severe corrosion of CAC #1 caused by boric acid corrosion from RCS leakage.
May 2002	CR 2002-02302	Leaks in the Boric Acid Evaporators, 1-1 and 1-2, have allowed boric acid to accumulate for years. There is visible rust on the skids, pipe hangers and pumps supports.
May 2002	CR 2002-2303	Water leaking from the Spent Fuel Pool has traveled through the surrounding concrete for years. The plant was unsuccessful in its attempt to find the leak during the RE-rack campaign. Degradation of rebar or interior concrete may be an issue.

Table E.5-1. Sample of Boric Acid Leakage, Corrosion, and Control Issues Documented by DBNPS (Continued)

Report Date	Report Number	Issue
May 2002	CR 2002-2305	Boric acid buildup on the incore tunnel wall leading under the reactor vessel of approximately ½ inch thick layer of what appears to be boric acid runs down the wall parallel to the steps approximately 4 feet up from the steps.
May 2002	CR 2002-2330	Degradation of CAC #2 due to boric acid corrosion. This CR lists 20 areas of general to severe corrosion of CAC #2 caused by boric acid from RCS leakage.
June 2002	CR 2002-2401	This CR addresses a mode restraint generated by CR 2000-0782 (involving buildup of boric acid on the RPV head) that was not cleared in a timely fashion.
June 2002	CR 2002-2414	Degradation of CAC #3 due to boric acid corrosion. This CR lists 20 areas of general to severe corrosion of CAC #3 caused by boric acid from RCS leakage.
June 2002	CR 2002-02430	Boric acid leakage from pressure transmitter PT-6365A. Leakage is red/brown indicating that corrosion is present.
June 2002	CR 2002-2655	Corrosion was discovered in pipe penetrations through the containment vessel. This CR does not indicate that boric acid caused or was partially responsible for the corrosion.
June 2002	CR 2002-02436	Boric acid leakage from pressure transmitter PT-RC2A5T. Leakage is red/brown indicating that corrosion is present.
June 2002	CR 2002-02440	Boric acid leakage from flow transmitter FT-RC1A4T at the manifold equalizing valve.
June 2002	CR 2002-02488	Boric acid leakage from pressure transmitter PT-RC2A1. Leakage is red/brown indicating that corrosion is present.
June 2002	CR 2002-02489	Boric acid leakage from pressure transmitter PT-RC2A3, packing leak at RC2A1B.
June 2002	CR 2002-02521	1/4 inch of water was discovered on the floor of the east west tunnel at the bottom of the ladder under CFT 1-1. Upon further investigation, discovered boron "bath tub ring" on the walls approximately 3 feet above the floor. Walls were boron free above this ring but covered with boron below this point.
June 2002	CR 2002-02572	The self-assessment of the ISI Pressure Test Program recommended improvements to the DBNPS BACC program, and its interface with the ISI Pressure Test Program.
June 2002	CR 2002-02625	Boric acid residue found on valve DH1517, valve DH1518, including the body to bonnet gasket area and the packing area including pressure retaining bolting.

Table E.5-1. Sample of Boric Acid Leakage, Corrosion, and Control Issues Documented by DBNPS (Continued)

Report Date	Report Number	Issue
June 2002	CR 2002-02632	Significant boric acid leakage and buildup on valve MU443 and its pipe cap.
June 2002	CR 2002-02767	Addresses concerns about cleaning methods for removing boric acid buildup on CACs, the RPV head and other areas. Runoff from cleaning has damaged components inside containment.
July 2002	CR 2002-03055	Addresses deficiencies with the BACC program (May 2002 version). The CR lists 15 issues (involving surveillance review, assessment, program coordination, documentation, operational experience information references, information databases, trending of event data, work order generation, scope of BACC program, and program management) with recommendations for each issue.
July 2002	CR 2002-03056	The BACC program engineer position does not have a position specific familiarization guideline (position description and qualification requirements). The CR suggests several specific qualification activities or knowledge that would be required of the engineer.
July 2002	CR 2002-03059	Suggests that the principal leak locations in the BACC program should be added to based on operational experience at DBNPS and at other nuclear power plants. Operational experience should be reviewed to update the BACC program.
July 2002	CR 2002-03066	The Boric Acid Corrosion database is a “rogue database” that might get corrupted since it is not a QA document. Greater protection of the database is required to maintain accurate records.
July 2002	CR 2002-03094	There is a lack of coordination between the BACC program and radiation protection procedures.
July 2002	CR 2002-03098	Boric acid buildup on valves and the floor in room 232. Blank flange not installed. Valves inside room 232 missing I.D. tags. Room 232 is a posted and locked high radiation area.
July 2002	CR 2002-03199	The BACC program is too limited in scope since it only involves boric acid leakage inside containment. Boric acid also exists outside of containment.

E.6.0 APPENDIX E ACRONYMS

ALARA	as low as reasonably achievable
ANO1	Arkansas Nuclear One, Unit 1
ANO2	Arkansas Nuclear One, Unit 2
ASME	American Society of Mechanical Engineers
BL	NRC bulletin
BRW1	Braidwood, Unit 1
BRW2	Braidwood, Unit 2
BV1	Beaver Valley, Unit 1
BV2	Beaver Valley, Unit 2
BYR1	Byron, Unit 1
BYR2	Byron, Unit 2
CAC	containment air cooler
CAL	Callaway
CAT1	Catawba, Unit 1
CAT2	Catawba, Unit 2
CC1	Calvert Cliffs, Unit 1
CC2	Calvert Cliffs, Unit 2
CEDM	control element drive mechanism
CIRC	circumferential
CPK1	Comanche Peak, Unit 1
CPK2	Comanche Peak, Unit 2
CRDM	control rod drive mechanism
CRY3	Crystal River, Unit 3
DB	Davis-Besse
DBNPS	Davis-Besse Nuclear Power Station
DCC1	D.C. Cook, Unit 1
DCC2	D.C. Cook, Unit 2
DIC1	Diablo Canyon, Unit 1
DIC2	Diablo Canyon, Unit 2
EFPY	effective full-power year
EPRI	Electric Power Research Institute
FAR1	Joseph M. Farley, Unit 1
FAR2	Joseph M. Farley, Unit 2
FPL	Florida Power and Light
FTC	Fort Calhoun
gpm	gallons per minute
GDC	general design criterion
GIN	R. E. Ginna
GL	NRC generic letter
HAR	Sharon Harris
HN	Haddam Neck
HPI	high pressure injection

IGA	intergranular attack
IN	NRC information notice
INSP	inspection
IPT2	Indian Point, Unit 2
IPT3	Indian Point, Unit 3
IWA	subsection of Section XI to the ASME Boiler and Pressure Vessel Code pertaining to general requirements
KEW	Kewaunee
MCG1	William B. McGuire, Unit 1
MCG2	William B. McGuire, Unit 2
MIL2	Millstone, Unit 2
MIL3	Millstone, Unit 3
MNSA	Mechanical Nozzle Seal Assembly
MY	Maine Yankee
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NA1	North Anna, Unit 1
NA2	North Anna, Unit 2
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation (NRC)
NSSS	Nuclear Steam System Supplier
NUMARC	Nuclear Utility Management and Resources Council (now NEI)
OCO1	Oconee, Unit 1
OCO2	Oconee, Unit 2
OCO3	Oconee, Unit 3
OPER	operating
PAL	Palisades
PDP	positive displacement charging pump
PI1	Prairie Island, Unit 1
PI2	Prairie Island, Unit 2
PTB1	Point Beach, Unit 1
PTB2	Point Beach, Unit 2
PT	liquid penetrant test
PV1	Palo Verde, Unit 1
PV2	Palo Verde, Unit 2
PV3	Palo Verde, Unit 3
PWR	pressurized-water reactor
PWSCC	primary water stress corrosion cracking
PZR	pressurizer
RCP	reactor coolant pump
RCS	reactor coolant system
RFO	refueling outage
RHR	residual heat removal

ROB	H. B. Robinson
RPV	reactor pressure vessel
RTD	resistance temperature detector
SAL1	Salem, Unit 1
SAL2	Salem, Unit 2
SCV	steel containment vessel
SEA	Seabrook
SEQ1	Sequoyah, Unit 1
SEQ2	Sequoyah, Unit 2
SON2	San Onofre, Unit 2
SON3	San Onofre, Unit 3
STL1	St. Lucie, Unit 1
STL2	St. Lucie, Unit 2
STP1	South Texas Project, Unit 1
STP2	South Texas Project, Unit 2
SUM	Virgil C. Summer
SUR1	Surry, Unit 1
SUR2	Surry, Unit 2
TI	temporary instruction
TMI1	Three Mile Island, Unit 1
TPT3	Turkey Point, Unit 3
TPT4	Turkey Point, Unit 4
UT	ultrasonic test
VH	vessel head
VHP	vessel head penetration
VOG1	Vogtle, Unit 1
VOG2	Vogtle, Unit 2
WAT3	Waterford, Unit 3
WB	Watts Bar
WC	Wolf Creek
ZIO1	Zion, Unit 1
ZIO2	Zion, Unit 2

APPENDIX F

SUMMARY OF RELATED ISSUES INVOLVING PREVIOUS NRC LESSONS-LEARNED EFFORTS

F.1 Scope

The task force reviewed the following reports from previous NRC lessons-learned activities to determine whether they suggested any recurring or similar problems:

- “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,” February 12, 1997 (Part 2 of this report included the recommendations from Part 1. The two reports are referred to here as the “Millstone Report”)

- “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

  Table F-1 summarizes the related issues.[1]

F.2 Review Results

The task force identified several areas in which previous assessments had uncovered performance or programmatic issues that are similar to some issues identified in this review. The task force did not conduct an extensive review of each of the previous lessons to determine what particular elements were common with the DBNPS event. The following is a brief description of these issues.

F.2.1 Closeout of Inspection Findings Before Licensee Implementation of Corrective Actions

The Millstone report recommended that guidance be issued for identification, followup and closeout of inspection findings.

As noted in Section 3.3.2 of this report, an open item involving a cited violation was closed without thorough inspection followup. The NRC inspection of the licensee’s corrective action implementation was not apparent.

---

[1]The recommendations related to Indian Point 2 are listed in a table in Section 9 of its report. The recommendations related to Millstone are listed in a table provided in the appendix to Part 2 of the report. The lessons and recommendations related to the South Texas Project are listed in Section 5 of its report. For ease of reference, Table F-1 provides recommendation numbers from the source documents, as applicable.

F.2.2 Program Guidance for Assessing Long-Standing Hardware Problems

The Indian Point 2 report recommended that the performance indicator or the inspection program be assessed to determine if revisions were needed to address trends in RCS leakage.

The South Texas Project report recommended that improvements were needed in assessing the effectiveness of long-term corrective action programs.

Sections 3.2.1, 3.2.2, 3.3.1, and 3.3.2 of this report discuss issues involving RCS leakage trends, PI&R inspection effectiveness, and long-standing or recurring hardware problems.

F.2.3 NRC Inspector/reviewer Skills, Abilities, Experience

The Indian Point 2 report recommended that NRC inspectors receive specialized training and that staff expertise in steam generator (SG) issues be maintained with formal training programs.

The Millstone report recommended that the NRC determine if inspectors have sufficient knowledge and skills needed to independently verify the acceptability of design-related actions.

The South Texas Project report recommended that the proper mix of skills and experience should be maintained between inspectors and supervisors.

Sections 3.3.1, and 3.3.5 of this report discuss issues involving a lack of training on boric acid corrosion control and PWSCC of Alloy 600 nozzles.

F.2.4 Process to Verify Information

The Millstone report had two recommendations related to development of processes to identify important aspects of plant-specific licensing actions and to verify their implementation.

The Indian Point 2 report recommended that guidance should be developed regarding NRR and Regional Office interface that might be needed to verify information submitted by licensees.

Section 3.1.2 of this report discusses issues involving the lack of independent verification of licensee provided information in connection with NRC Bulletin 2001-01 VHP nozzle inspections. Sections 3.1.2 and 3.1.5 discuss issues involving unverified assumptions pertaining to VHP nozzle cracking and its effects on the RPV head. Also, Section 3.3.7 discusses issues involving the approval of a LAR related to the RCS leakage detection system in which those staff members processing the LAR were unaware of the fouling of the associated radiation monitors.

F.2.5 NRC Review of Routine Reports

The Indian Point 2 report recommended that the NRC assess the need for and processes related to the review of routinely submitted (SG) inspection reports required by TS.

Section 3.3.7 of this report discusses issues involving the lack of review of licensee inservice inspection summary reports and other licensee submitted information, such as summary reports involving changes to commitments.

F.2.6 NRR/Regional Office Interaction During Safety Evaluation Development

The Indian Point 2 report recommended that guidance should be developed regarding NRR and Regional Office interface that might be needed to verify information submitted by licensees.

Section 3.3.7 of this report discusses the level of awareness of RCS leakage detection system radiation monitor filter element fouling relative to the processing of a TS amendment request involving that system.

F.2.7 Specific Review Guidance

The Indian Point 2 report recommended that formal guidance be provided to staff reviewers of SG-related submittals.

Sections 3.1.2 and 3.3.7 of this report discuss issues involving the level of guidance for the review of generic communication submissions.

F.2.8 Integration of Inspection Findings

The South Texas Project report recommended that the process of integrating findings be examined for areas of possible improvement.

Sections 3.3.1 through 3.3.3 of this report discuss a number of issues involving the lack of integrations and assessment of inspection findings.

F.2.9 Performance Review Process

The Indian Point 2 report recommended that additional guidance be developed to support SG inspection for the baseline inspection program.

The South Texas Project report recommended that improvements were needed in inspection guidance and inspector oversight needed to be strengthened.

The Millstone report had a recommendation related to NRC processes used to assess plant performance.

Sections 3.3.1 through 3.3.4 of this report discuss issues involving inspection guidance and oversight in a number of areas, including RCS leakage.

F.2.10 Inadequate Industry Guidance

The Indian Point 2 report recommended that EPRI SG guidelines be improved.

Sections 3.1.4 and 3.3.4 discuss issues involving the technical adequacy of industry guidance involving VHP nozzle cracking and boric acid corrosion control.

F.2.11 Inadequate Requirements in Licensing Basis

The Indian Point 2 report recommended TS improvements related to PWR SG requirements.

Sections 3.2.1 and 3.3.4 of this report discuss issues involving the adequacy of various requirements includingTS involving RCS leakage.

F.3 Recommendation

The NRC should conduct an effectiveness review of the actions taken in response to past lessons-learned reviews.

Table F-1 Summary of Issues from Previous Lessons-Learned Reviews Related to The Davis-Besse Event

Issue Related to Davis Besse	**DBLL Recommendation No.** (See App. A)	**Related Previous Lessons or Recommendations**
F.2.1 Closeout of inspection findings before licensee implementation of corrective actions	3.3.2(4)	Millstone (item 4)
F.2.2 Program guidance for assessing long-standing hardware problems	3.2.1(2), (3), 3.2.2(1) 3.3.1(1), (2), 3.3.2(1), (2)	South Texas Project Indian Point 2 (item 5e)
F.2.3 NRC Inspector/reviewer skills, abilities, and experience	3.3.1(1), 3.3.5(1)	Indian Point 2 (items 5b, 5c) Millstone (item 14) South Texas Project
F.2.4 Process to verify information	3.1.2(1), 3.3.7(1)	Millstone (items 2 and 6) Indian Point 2 (item 6d)
F.2.5 NRC review of routine reports	3.3.7(5), (6)	Indian Point 2 (item 6c)
F.2.6 NRR/Regional office interaction during safety evaluation development	3.3.7(1)	Indian Point 2 (item 6d)
F.2.7 Specific review guidance	3.1.2(4), 3.3.7(2)	Indian Point 2 (item 6a)
F.2.8 Integration of inspection findings	3.3.2(3), (4), 3.3.3(2)	South Texas Project
F.2.9 Performance review process	3.3.3(1), (2)	Indian Point 2 (items 5a, 5f) South Texas Project Millstone (item 15)
F.2.10 Inadequate industry guidance	3.1.4(1) 3.3.4(8)	Indian Point 2 (item 2)
F.2.11 Inadequate requirements in licensing basis	3.2.1(1), 3.3.4(8), (9)	Indian Point 2 (item 3)