Reference A

August 1,2001

MEMORANDUM TO: Stephen Dinsmore
Probabilistic Safety Assessment Branch
Division of Systems Safety and Analysis

FROM: Walton Jensen ***/RA/***
Reactor Systems Branch
Division of Systems Safety and Analysis

SUBJECT: CRDM THIMBLE RUPTURE SENSITIVITY STUDY

You requested evaluations of potential CRDM thimble ruptures in operating PWRs to help assess applicability of existing PRA evaluations for hot leg breaks. Leaks and cracks in the CRDM thimbles were recently observed at Oconee and have subsequently been observed at other operating PWRs. The failure of a CRDM thimble would produce the equivalent of a small break LOCA. Small break LOCA is traditionally evaluated for piping ruptures in primary coolant piping and in connected smaller piping. The rupture of a CRDM thimble would cause a leak directly in the reactor vessel upper head. There is concern that the event would evolve in a different manner than that expected by plant operators and cause confusion.

We preformed the following series of calculations for Oconee using the RELAP5 computer code using an input model prepared by INEEL. Both loops of the reactor system and portions of the steam and feedwater systems are described in the RELAP model of the plant.

1. The rupture of a single CRDM thimble with AFW and minimum HPI flow.

2. The rupture of two CRDM thimbles with AFW and minimum HPI flow.

3. The rupture of three CRDM thimbles with AFW and minimum HPI flow.

4. A leak in the upper reactor vessel head equivalent to one half the area of a CRDM thimble with AFW and minimum HPI flow.

5. The rupture of a single CRDM thimble without AFW, HPI or steam dump capability to the condenser.

6. A hot leg leak equivalent in area to a CRDM thimble. AFW, HPI and steam dump capability to the condenser were assumed to be unavailable.

CONTACT:
WJensen, DSSA/SRXB
415-2856

In these analyses the reactor coolant pumps were assumed to trip at the same time the break opened. Actually operators are instructed to trip the coolant pumps manually on loss of subcooling as indicated on a monitor in the control room. Operator action was assumed to raise the steam generator level to 95% on the operating range as required by procedures on loss of forced flow and subcooling. This action was assumed to occur 600 seconds after the break opened.

Cases 1 through 4 approximate the assumptions made in the plant's design basis. No unusual phenomena were calculated to occur. The reactor system did not repressurize significantly from loss of natural circulation and the reactor core remained covered. Figure 1 is a plot of system pressure in the reactor and steam generators for the single CRDM thimble case. The steam generators are cooled and depressurized by the addition of auxiliary feedwater until the required level of 95% on the operating range is reached at 1452 seconds. After that time steam generator cooling is temporarily interrupted. The primarily system water level continued to decrease to a level corresponding to that in the steam generators. This occurs at approximately 2000 seconds. At that time rapid depressurization occurred. The 95 percent steam generator level is well above the core and provides an adequate heat sink before core uncovery can occur. See NUREG-0565, "Generic Evaluation of Small Break Loss-of-Coolant Accident Behavior in Babcock & Wilcox Designed 177-FA Operating Plants," January 1980. The reactor system eventually reached an equilibration pressure of approximately 500 psi corresponding to a balance of heat removed by the break and added by the reactor core. Other break sizes exhibited a similar response with the larger breaks reaching a lower equilibrium pressure and the smaller break reaching a higher equilibrium pressure.

The borated water storage tank (BWST) at Oconee contains a minimum inventory of 415,200 gallons, approximately 14 hours of injection water would be available (one HPI pump) before operators would be required to recirculate containment sump water for continued ECCS cooling. This could be accomplished by the low pressure injection system (LPIS) injecting directly into the reactor vessel if operators depressurized the plant. Alternately the HPI could continue to be operated during the recirculation period taking suction from the LPIS pump discharge.

The analysis in case 5 with no HPI or AFW flow was made for the purpose of determining the time available for manual restoration of safeguards equipment and comparison to the similar analysis of a hot leg break of the same size. The result of this comparison is shown in Figure 2. A much longer time was required for beginning of core uncovery for a break in the top of the reactor vessel than for an equivalent break in a hot leg. The Oconee design with once through steam generators includes hot leg piping that extends 43 feet above the core. A break at the top of the reactor vessel permits this liquid to flow into the core before uncovery can occur. The hot leg break was located close to the reactor vessel in the horizontal section. Much of the liquid in the vertical hot leg sections was lost out the break before it could reach the core. These results indicate that PRA conclusions for hot leg break close to the reactor vessel would be conservative if applied to a potential CRDM break.

So that the effect of break location could be assessed for other PWR designs, we preformed the following additional RELAP5 analyses.

6. The rupture of a single CRDM thimble without AFW, HPI or steam dump capability to the condenser for a four loop Westinghouse plant (Seabrook).

7. The rupture of a single CRDM thimble without AFW, HPI or steam dump capability to the condenser at a Combustion Engineering plant (ANO-2).

These analyses were compared to the equivalent break size in a hot leg. The conclusions for Seabrook are the opposite of those for Oconee. For Seabrook a CRDM thimble break at the top of the vessel caused core dryout to begin earlier than for a hot leg break (Fig. 3). The reason for the difference in results lies in the design of the reactor vessel internals. In both designs the upper head is separated from the upper plenum by a plenum cover plate. In the Oconee design the plenum cover plate is porous providing an open path for coolant to flow up through the control rod guide tubes and down through the plenum cover plate into the upper plenum. The upper head at Oconee is heated to the temperature of the core outlet during operation. For the Seabrook design flow within the upper head is restricted. During operation leakage flow is permitted from the reactor vessel downcomer into the upper head. Flow then passes downward through the control rod guide tubes to the top of the core. During operation the upper head at Seabrook is approximately at the core inlet temperature.

For a postulated CRDM break at Oconee flow from the core to the break is primarily though the upper plenum where the large flow area permits steam/water separation so that steam can flow out the break and water can remain above the core. For a CRDM thimble break at Seabrook, flow from the core to the break is primarily through the control rod guide tubes which have a small hydraulic diameter and permit little steam/water separation. Water from the core is sucked up to the break through the control rod guide tubes in a process similar to drinking through straw. The reactor vessel internal design for a typical Westinghouse plant is shown in Figure 4.

The upper head flow design at ANO-2 is less restrictive than that for Seabrook but more restricted than Oconee. During operation the upper head temperature is between that of the core inlet and that of the core outlet. The time for the beginning of core dryout was found to be approximately the same whether the break was in the upper head or in a hot leg. See Figure 5.

In summary the conclusions from this study are that a break in a CRDM thimble produces the effect of a small break LOCA. No new phenomena were identified from those which have already been evaluated.

In investigating the effect of break location, use of hot leg break analyses appear to be conservative in describing a CRDM thimble break for Oconee and slightly conservative for ANO2. Use of hot leg break analyses to describe a CRDM thimble break at Seabrook does not appear to not be conservative.

Attachment:
As stated

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Reference B

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

May 10, 2002

MEMORANDUM TO: Gary Holahan, Director
Division of Systems Safety and Analysis

THRU: Ralph Caruso, Section Chief
Section Chief, Reactor Systems Branch
Division of Systems Safety and Analysis

FROM: Walton Jensen
Reactor Systems Branch
Division of Systems Safety and Analysis

SUBJECT: SENSITIVITY STUDY OF PWR REACTOR VESSEL BREAKS

This memorandum documents a study using RELAP5 to determine the consequences of postulated breaks in the reactor vessel of PWRs. The study was performed in response to questions arising following recent occurrences of cracks in CRDM housings at several PWRs and corrosion in the upper head at Davis Besse. Breaks up to 8 inches in diameter (0.349 ft^2) were analyzed in the upper reactor vessel head. Most of the analyses were for a B&W design (Oconee) with discussions of the effect of plant differences between Oconee and Davis Besse. Plant designs by Westinghouse and CE were also analyzed. Full and partial plant safeguards, delayed reactor pump trip and failure to scram were analyzed.

For postulated breaks in the upper head, the consequences are similar to piping breaks analyzed in plant FSARs as part of the design basis. No new phenomena or unexpected results were obtained. Plants designed by all three PWR reactor vendors were analyzed.

The consequences of failure to scram were evaluated and found to be minimal. This is because of the negative reactivity produced by core voiding and later by boric acid addition.

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SENSITIVITY STUDY FOR BREAKS IN THE REACTOR VESSEL

Walton Jensen
DSSA/SRXB

1. BACKGROUND

Leaks and cracks in the CRDM thimbles have been observed at Oconee and were subsequently observed at other operating PWRs. The extensive upper head pitting at Davis-Besse has added interest to the consequences of a LOCA in a reactor vessel upper head. This is a break location not routinely analyzed in plant FSARs except for the consequences of an ejected control rod assembly that might result from the rupture of a CRDM thimble. The LOCA that would result from the rupture of a single CRDM thimble is judged to be bounded by the larger break sizes assumed to occur in the coolant piping in FSAR analyses. As part of this study the reactor response to a postulated upper head break is compared to a break of equivalent size in the coolant piping.

Breaks up to an equivalent diameter of 8 inches (0.349 ft^2) are analyzed in the top head of PWRs. B&W defines small breaks as less than 0.5 ft^2. Westinghouse defines small breaks as less than 1.0 ft. For the purposes of LOCA analysis the break sizes analyzed in this study are all in the small break range.

2. ANALYSIS OF REACTOR VESSEL UPPER HEAD BREAKS

We utilized a RELAP5 input model prepared by INEL for Oconee (Ref. 1). Both loops of the reactor system and portions of the steam and feedwater systems are described in the RELAP5 model. Davis Besse is a Babcock and Wilcox plant similar to Oconee. The major difference is that Davis Besse has a raised loop design which means that the once through steam generators are above the reactor core. See Figure 1. The hot legs are extended upward and provide an additional source of water above the core in comparison to Oconee. The lowered loop arrangement for Oconee and the other B&W operating plants is shown in Figure 2.

Seven RELAP5 cases were analyzed for Oconee. Cases 1 through 5 are for breaks in the upper head of progressively larger size to explore the occurrence of unexpected phenomena. Case 4 assumes operators were late in tripping the reactor coolant pumps on loss of subcooling margin as required by procedures. Cases 6 and 7 explore the consequences of the control rods not being inserted. Cases 8 and 9 compare the consequences of a CRDM break to a break of equivalent size in a hot leg. In all these analyses the first 100 seconds is a null transient to achieve steady state. The break occurs at the end of 100 seconds in the attached plots.

<u>Oconee Cases with Partial Safeguards</u>

Case 1: The rupture of a single CRDM thimble with AFW and minimum HPI flow. See Figures 3 and 4.

Case 2: The rupture of two CRDM thimbles with AFW and minimum HPI flow. See Figures 5 and 6.

Case 3: The rupture of three CRDM thimbles with AFW and minimum HPI flow. See Figures 7 and 8.

Case 4: The rupture of three CRDM thimbles with AFW and minimum HPI flow and delayed reactor coolant pump trip. See Figure 10.

Case 5: A rupture in the reactor vessel head 8 inches in diameter with AFW and minimum HPI flow. See Figures 11 and 12.

Case 6: A rupture in the reactor vessel head 8 inches in diameter with AFW and minimum HPI flow for which the control rods did not insert. See Figures 13 and 14.

Case 7: The rupture of a single CRDM thimble with AFW and minimum HPI flow for which the control rods did not insert. See Figures 15 and 16.

Case 8: The rupture of a single CRDM thimble without AFW, HPI or steam dump capability to the condenser. See Figure 17.

Case 9: A hot leg leak equivalent in area to a CRDM thimble. AFW, HPI and steam dump capability to the condenser were assumed to be unavailable. See Figure 17.

In all analyses but case 4 the reactor coolant pumps were assumed to trip on loss of subcooling margin in accordance with emergency procedures. In all cases but 8 and 9 operator action was assumed to raise the steam generator level to the top of the operating range as required by procedures on loss of forced flow and subcooling.

Cases 1, 2. 3, and 5 approximate the assumptions made in the plant's design basis. No unusual phenomena were calculated to occur. Because of the coolant loop arrangement of Babcock and Wilcox designed reactors natural circulation can be lost during a small break LOCA so that the core can be isolated from the heat removal capabilities of the steam generators. Loss of natural circulation would cause an increase in reactor system pressure and an increase in water loss from the break. Operators are instructed to manually increase steam generator level following loss of subcooling margin to ensure that the core remains covered. This action was assumed to be taken at ten minutes after the break occurred. No significant loss of natural circulation was calculated to occur and no core uncovery was calculated.

As the break sizes became larger the reactor was depressurized by break flow without the need for steam generator heat removal. For smaller breaks operator action to depressurize the steam generators would be required to make low pressure safety injection effective for the establishment of long term cooling. Figure 5 shows the effect of operator action in enhancing cooldown so that low pressure safety injection could be successfully initiated.

Effect of Delayed Reactor Coolant Pump Trip (Case 4)

After TMI-2 the need to trip the reactor coolant pumps on loss of subcooling margin was recognized. For a range of small break sizes a window of time was identified for which if the reactor coolant pumps were tripped within the window, extended core uncovery might occur. The window calculated by B&W is shown in Figure 9. For the 3-CRDM break case operator action in tripping the coolant pumps was assumed to be delayed so that the trip occurred after 10 minutes which is in the middle of the window period. The effect of the delayed pump trip (Figure 10) was a spike in core voiding but core uncovery was not predicted by RELAP5.

Effect of Failure to Scram (Cases 6 and 7)

Normally control rod entry is assumed for SBLOCA but not for LBLOCA because of concern that hydraulic forces would interfere with control rod motion following a large break. The 8 inch break size was the largest break size examined and is analyzed here to determine the consequences of failure of the control rods to enter the core.

For the 8 inch break size the reactor system was predicted to depressurize rapidly and decrease below that of the steam generators since this break size is sufficient to remove all decay heat (Figure 11). LPI was automatically initiated and no core uncovery was predicted (Figure 12). The effect of failure of the control rods to enter the core was minimal. The core did not uncover for this case and the calculated core void fractions (Figure 13) are almost identical to those for the case for which the control rods were assumed to be inserted. The reason for this is that voiding in the reactor core shuts down the reactor with negative reactivity soon after the break occurs. See Figure 14. Further negative reactivity is added by the boric acid in the core flood tanks and in the HPI and LPI water. A degree of positive reactivity addition occurs from temperature reactivity feedback but the boric acid addition is sufficient to overcome this effect.

The failure of a single CRDM thimble was also analyzed with the assumed failure of the control rods to enter the core. This break size would be expected to depressurize slower that the 8 inch break size so that negative reactivity from void formation and boron addition would be expected to occur later. This case is the same as case 1 with the exception that the control rods did not enter the core. The failure of the control rods had little effect on the results. Void formation rapidly reduced the core power level. The core was predicted to remain covered with water. See Figure 15. Core reactivity with and without scram is shown in Figure 16. The reactivity is continuously negative. The sudden increase in reactivity after 2000 seconds is the result of cold water entering the core from the core flood tanks displacing some of the steam bubbles. The core cannot return to critical from addition of this water since it contains 2000 ppm of boric acid.

Comparison or an Upper Head Break to a Break in a Hot Leg (Cases 8 and 9)

Figure 17 shows the effect of break location on the consequences from a LOCA. No feedwater or ECCS was assumed in these analyses so that the core would dry and begin to heat up. This was so that the time to dryout could be compared as a figure of merit to judge the severity of the break location. The time to dryout also gages the time available for operator action to restore safeguards equipment if required. A much longer time was required for core uncovery for a break in the top of the reactor vessel than for an equivalent break in a hot leg. The hot leg break was located close to the reactor vessel in the horizontal section. Much of the liquid in the vertical hot leg sections was lost out the break before it could reach the core. The Oconee design with once through steam generators includes hot leg piping that extends 43 feet above the core. A break at the top of the reactor vessel permits this liquid to flow into the core and extends the time to core uncovery. The hot legs at Davis-Besse extend even further above the core and should provide even more water for core cooling than Oconee. These results indicate that PRA conclusions for a hot leg break close to the reactor vessel would be conservative if applied to a potential CRDM break at Oconee or Davis-Besse.

Upper Head Break Cases for Westinghouse and CE Designs

So that the effect of break location could be assessed for other PWR designs, we preformed the following additional RELAP5 analyses. These analyses utilized an input deck prepared by INEL for Seabrook (Ref. 2) and for ANO-2 (Ref. 3). No feedwater or ECCS was assumed in these analyses so that the core would dry out and begin to heat up. This was so that the time to dryout could be compared as a figure of merit to judge the severity of the break location.

Case 10: The rupture of a single CRDM thimble without AFW, HPI or steam dump capability to the condenser for a four loop Westinghouse plant (Seabrook). See Figure 18.

Case 11: A break in a hot leg equivalent to the size to a single CRDM thimble without AFW, HPI or steam dump capability to the condenser for a four loop Westinghouse plant (Seabrook). See Figure 18.

Case 12: A break in a cold leg equivalent in size to a single CRDM thimble without AFW, HPI or steam dump capability to the condenser for a four loop Westinghouse plant (Seabrook). See Figure 18.

Case 13: The rupture of a single CRDM thimble without AFW, HPI or steam dump capability to the condenser at a Combustion Engineering plant (ANO-2). See Figure 19.

Case 14: A break in a hot leg equivalent to the size to a single CRDM thimble without AFW, HPI or steam dump capability to the condenser for a four loop Westinghouse plant (ANO-2). See Figure 19.

The conclusions for Seabrook in comparing a CRDM break and a hot leg break are the opposite of those for Oconee. For Seabrook a CRDM thimble break at the top of the vessel caused core dryout to begin earlier than for a hot leg break (Fig. 18). The reason for the difference in results lies in the design of the reactor vessel internals. In both designs the upper head is separated from the upper plenum by a plenum cover plate. In the Oconee design the plenum cover plate is porous providing an open path for coolant to flow up through the control rod guide tubes and down through the plenum cover plate into the upper plenum. The upper head at Oconee is heated to the temperature of the core outlet during operation. For the Seabrook design, flow within the upper head is restricted. During operation leakage flow is permitted from the reactor vessel downcomer into the upper head. Flow then passes downward through the control rod guide tubes to the top of the core.

During operation the upper head at Seabrook is approximately at the core inlet temperature.

For a postulated CRDM break at Oconee flow from the core to the break is primarily though the upper plenum where the large flow area permits steam/water separation so that steam can flow out the break and water can remain above the core. For a CRDM thimble break at Seabrook, flow from the core to the break is primarily through the control rod guide tubes which have a small hydraulic diameter and permit little steam/water separation. Water from the core is sucked up to the break through the control rod guide tubes in a process similar to drinking through straw. Note in Figure 18 that for Seabrook that the consequences of a CRDM rupture are more advantageous than for a cold leg break. The results lie between the hot leg and cold leg break cases so the CRDM break is thus still bounded by the FSAR analysis.

The upper head flow design at ANO-2 is less restrictive than that for Seabrook but more restricted than Oconee. During operation the upper head temperature is between that of the core inlet and that of the core outlet. The time for the beginning of core dryout was found to be approximately the same whether the break was in the upper head or in a hot leg. See Figure 19.

In investigating the effect of break location, use of hot leg break analyses appear to be conservative in describing a CRDM thimble break for Oconee and slightly conservative for ANO2. Use of cold leg break analyses to describe a CRDM thimble break at Seabrook would be conservative.

3. CONCLUSIONS

For postulated breaks in the upper head of a PWR reactor vessel the consequence are similar to piping breaks analyzed in plant FSARs as part of the design basis. No new phenomena or unexpected results were obtained. Plants designed by all three reactor vendors were analyzed.

The consequences of failure to scram were evaluated and found to be minimal. This is because of the negative reactivity produced by core voiding and later by boric acid addition.

REFERENCES

1. K. S. Quick, "Oconee Unit 1 Pressurized Water Reactor RELAP5/Mod3 Input Model," Idaho National Engineering Laboratory, August 1994.

2. J. R. Larson and J. D. Burtt, "Seabrook Pressurized Water Reactor RELAP5/Mod3 Model," September 1994.

3. W. K. Terry, "Arkansas Nuclear One, Unit 2 RELAP5/Mod3.2 Input Model," June 1996.

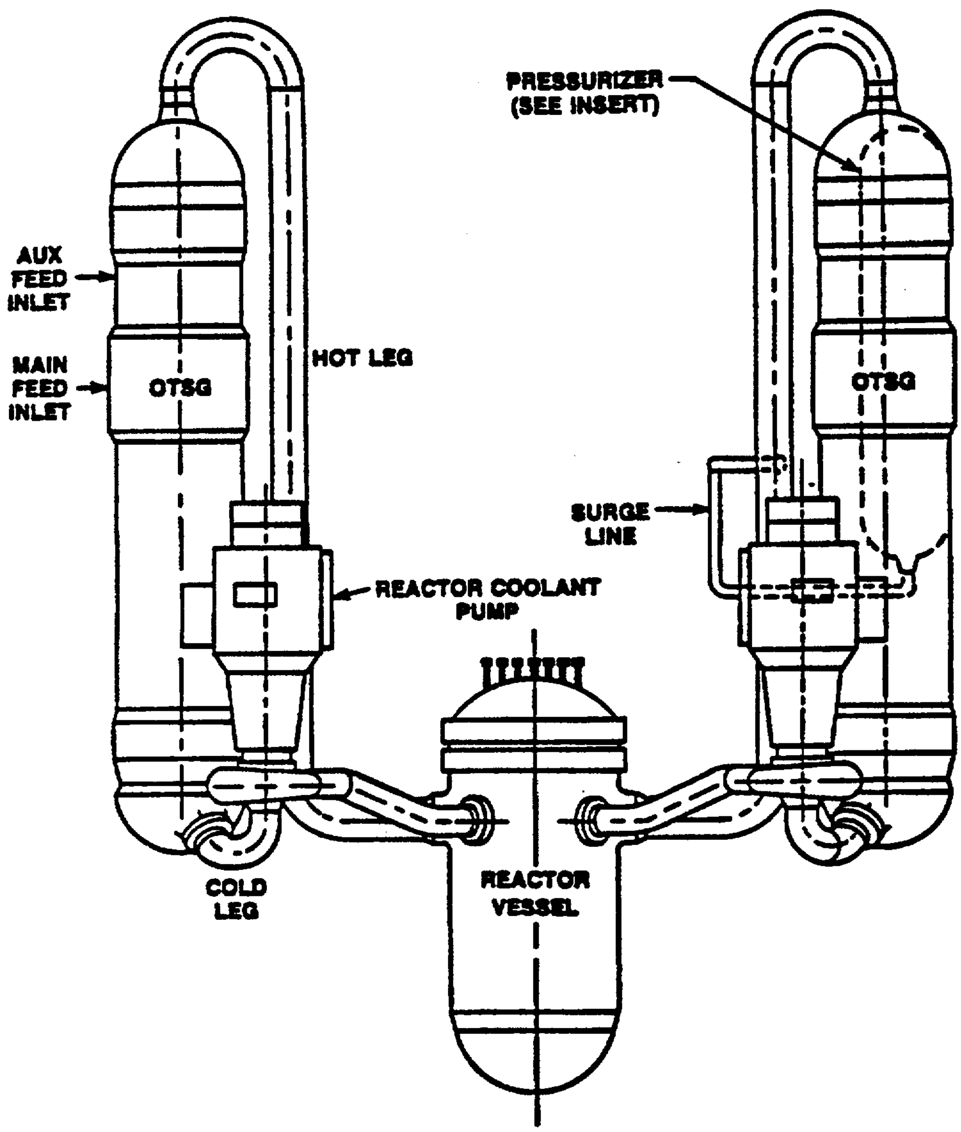


Figure 1 Babcock & Wilcox 177 "Raised-Loop" PWR NSSS

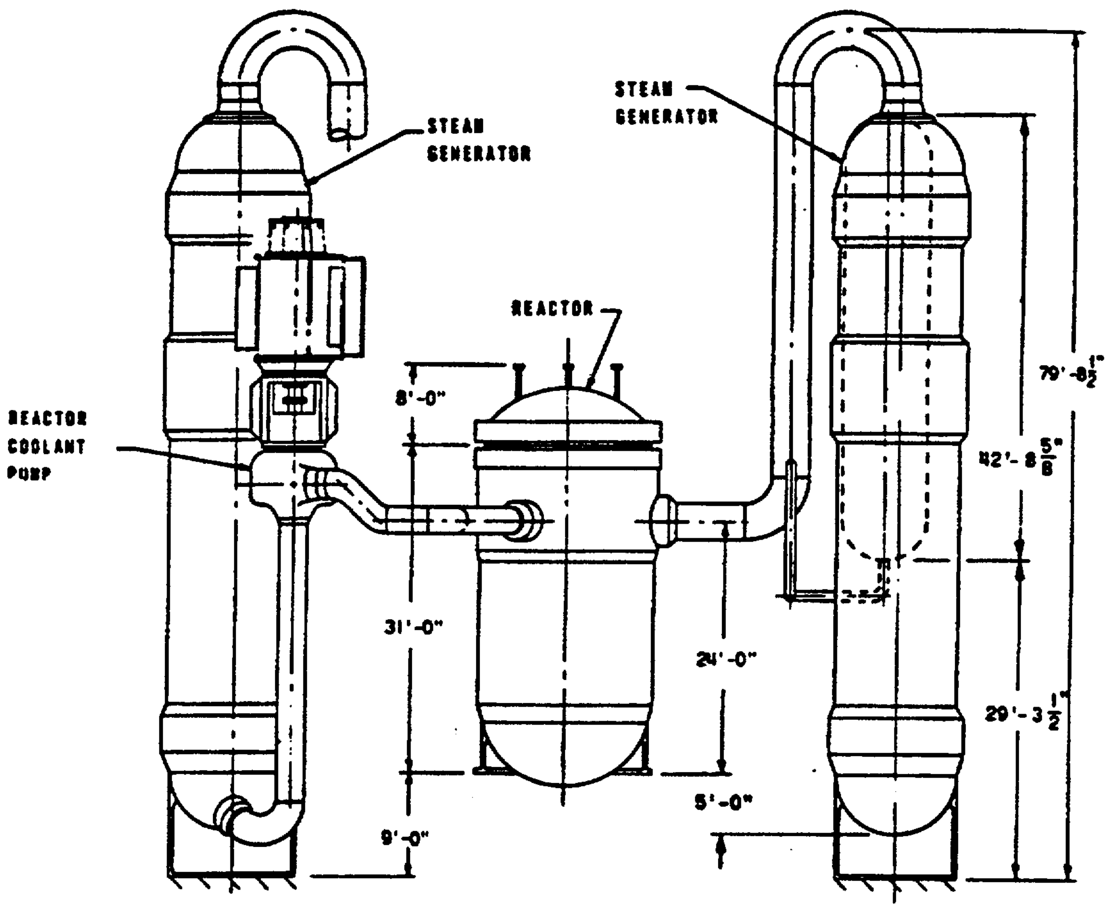


Figure 2 Babcock & Wilcox 177 "Lowered-Loop" PWR NSSS

Oconee

Control Rod Housing Break

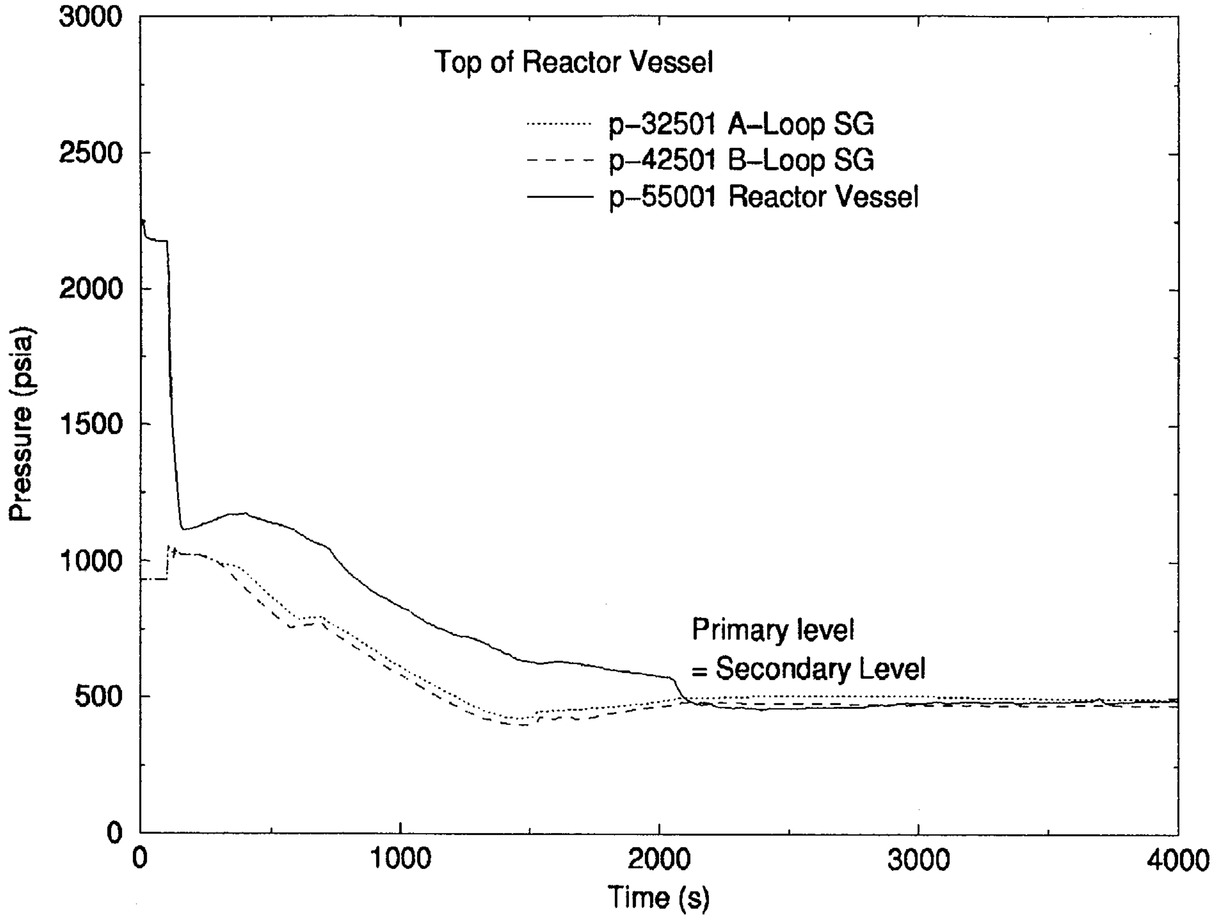


Figure 3

Oconee

Control Rod Housing Break

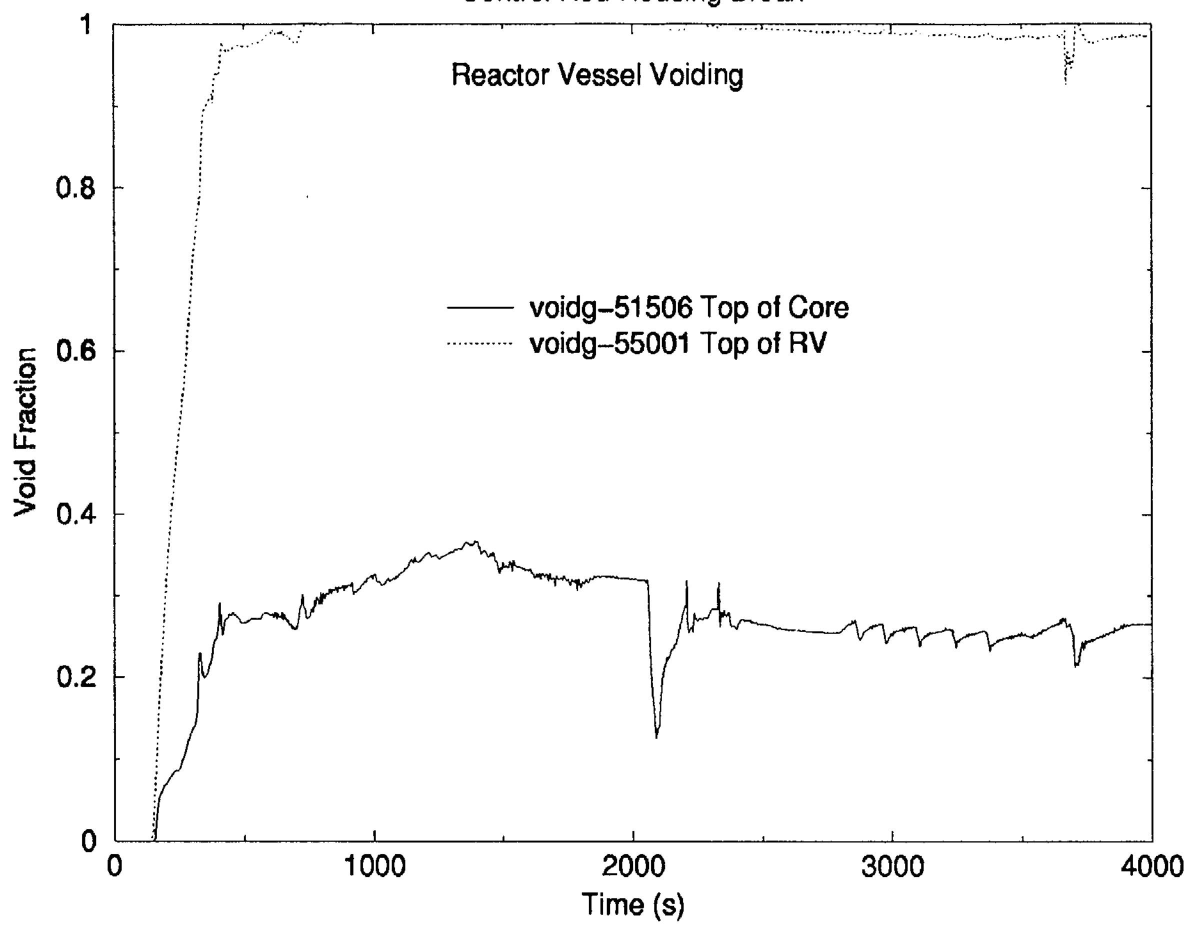


Figure 4

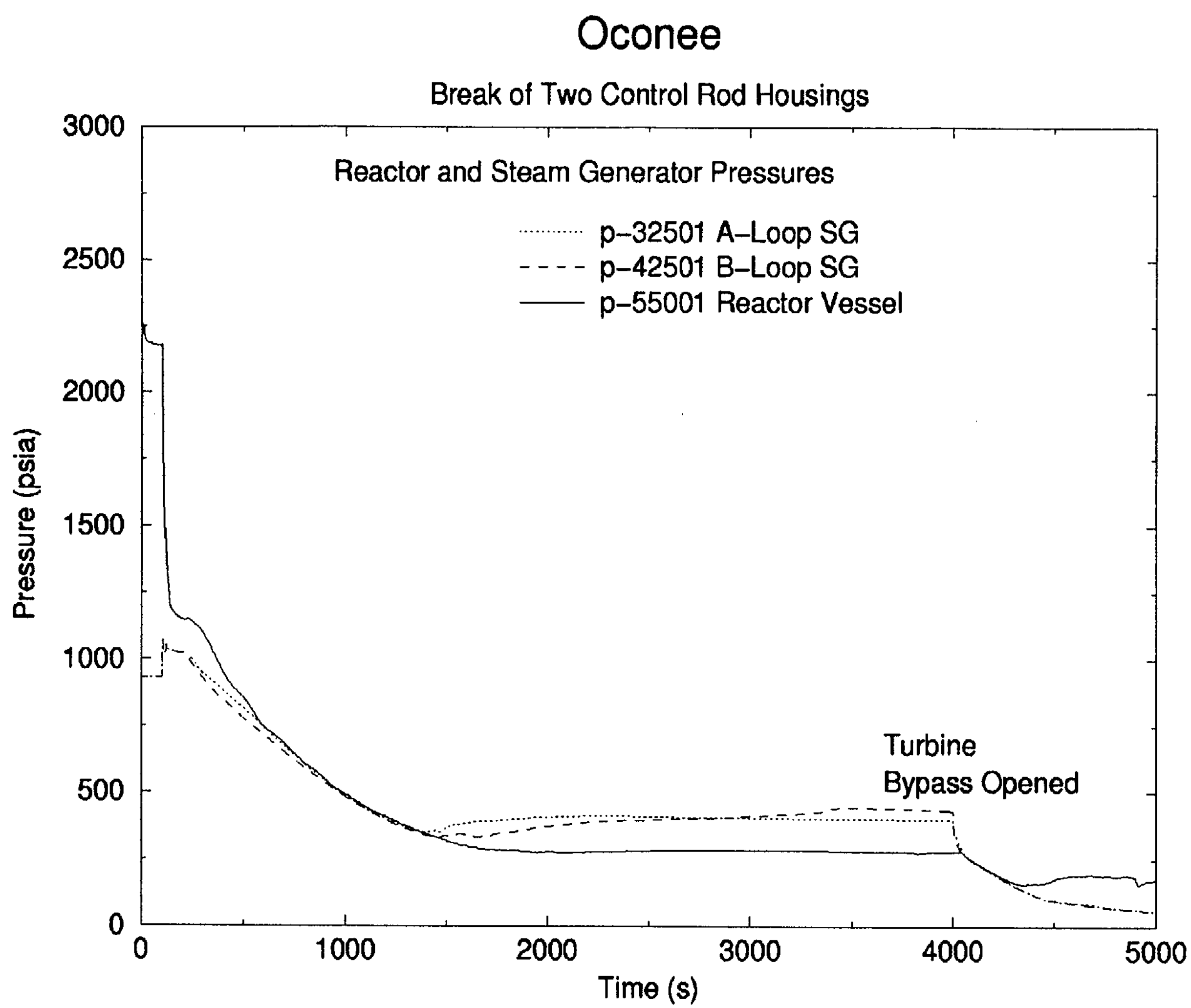
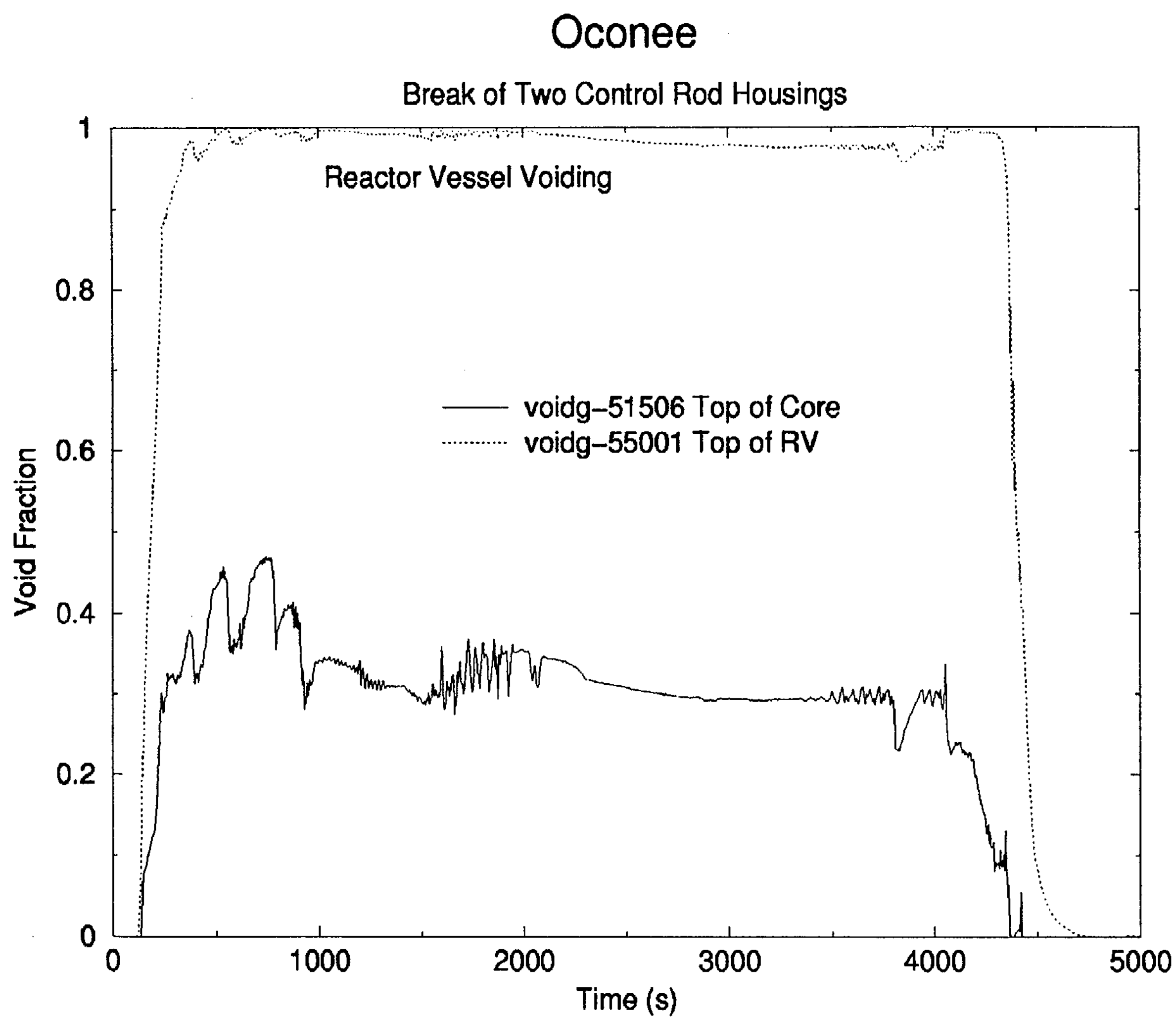

Oconee
Break of Two Control Rod Housings
Reactor and Steam Generator Pressures
p-32501 A-Loop SG
p-42501 B-Loop SG
p-55001 Reactor Vessel
Turbine
Bypass Opened
Pressure (psia)
Time (s)
0
500
1000
1500
2000
2500
3000
0
1000
2000
3000
4000
5000

Figure 5



Oconee
Break of Two Control Rod Housings
Reactor Vessel Voiding
voidg-51506 Top of Core
voidg-55001 Top of RV
Void Fraction
Time (s)
0
0.2
0.4
0.6
0.8
1
0
1000
2000
3000
4000
5000

Figure 6

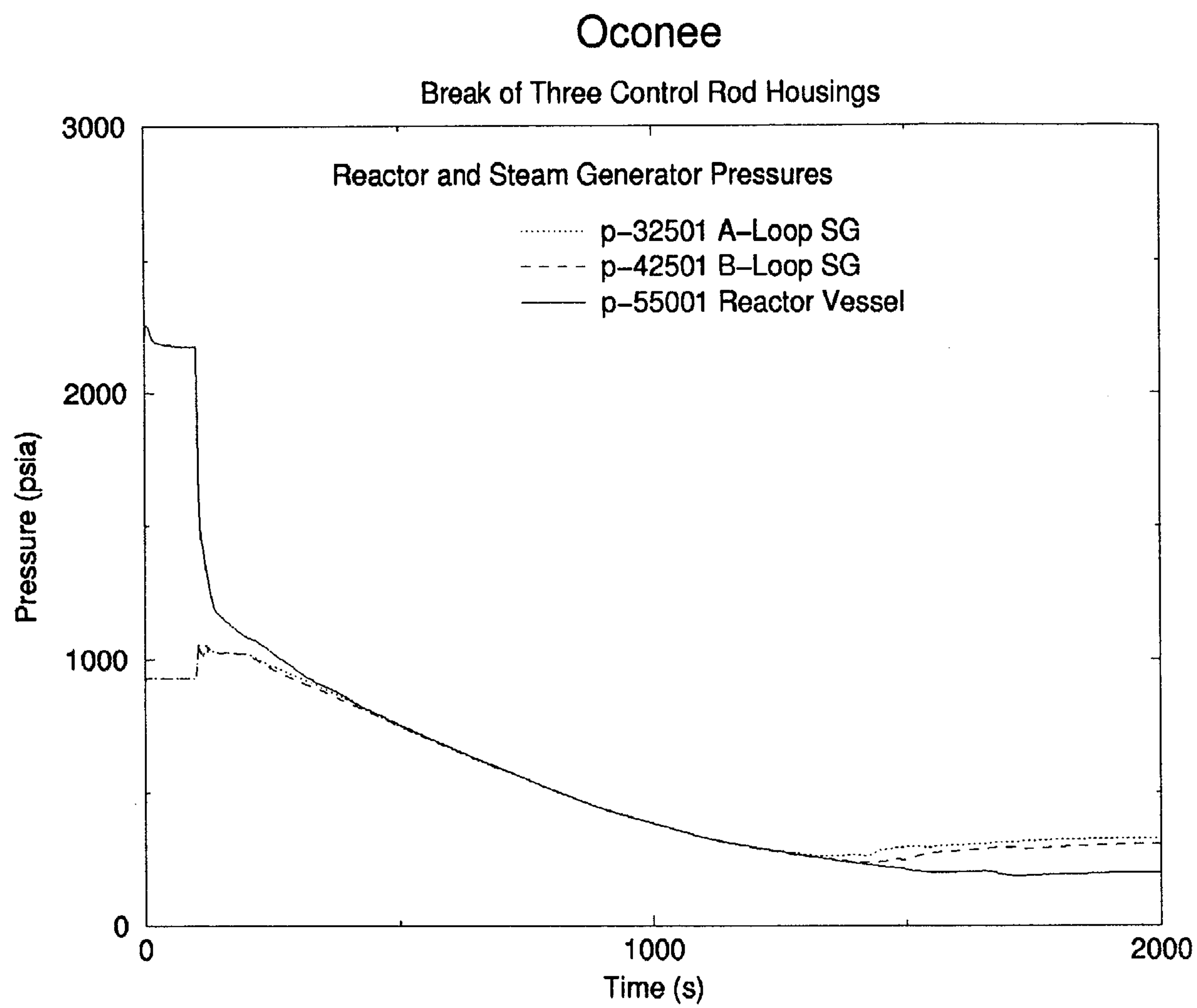

Oconee
Break of Three Control Rod Housings
Reactor and Steam Generator Pressures
p-32501 A-Loop SG
p-42501 B-Loop SG
p-55001 Reactor Vessel
Pressure (psia)
3000
2000
1000
0
0
1000
2000
Time (s)

Figure 7

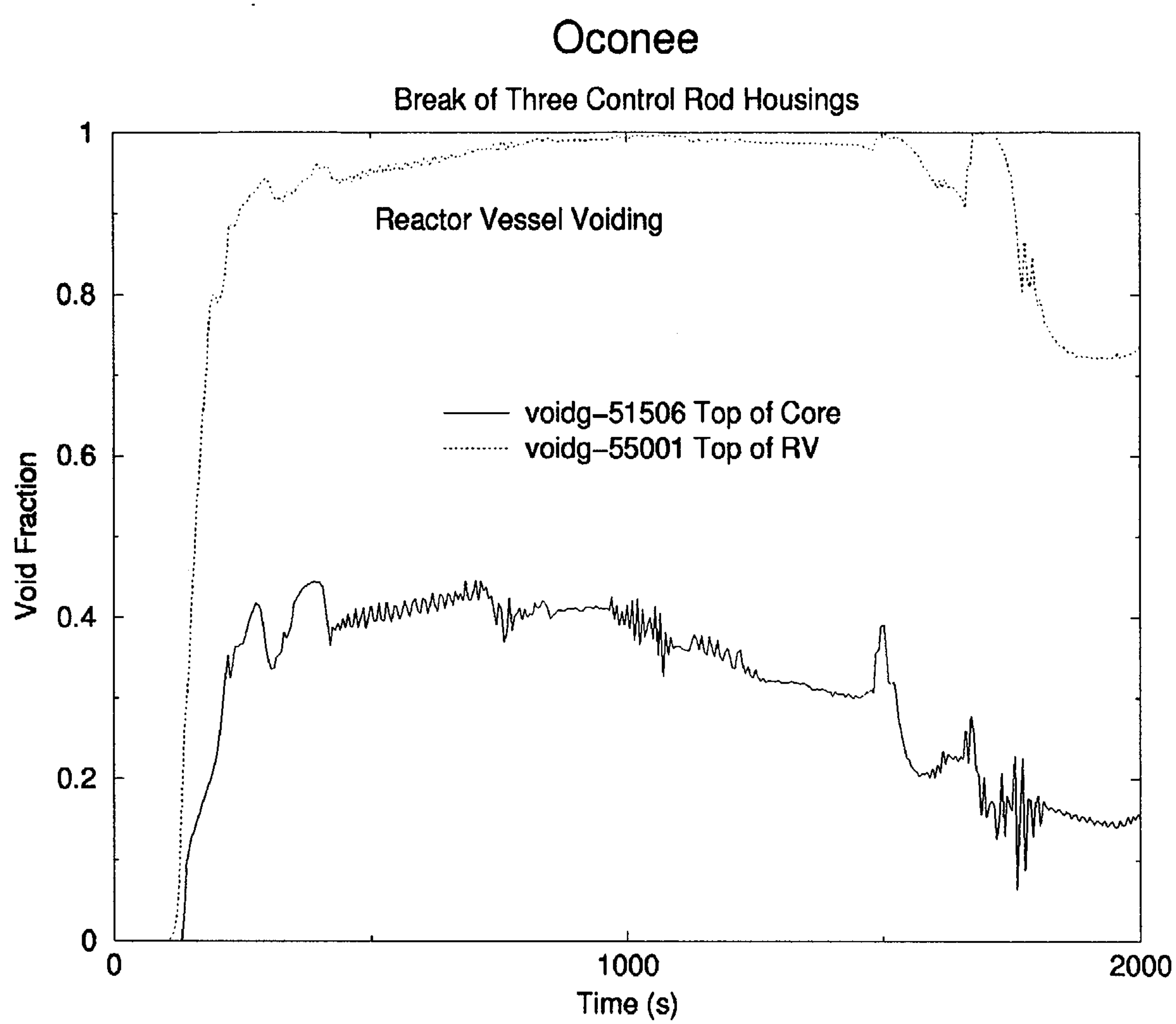
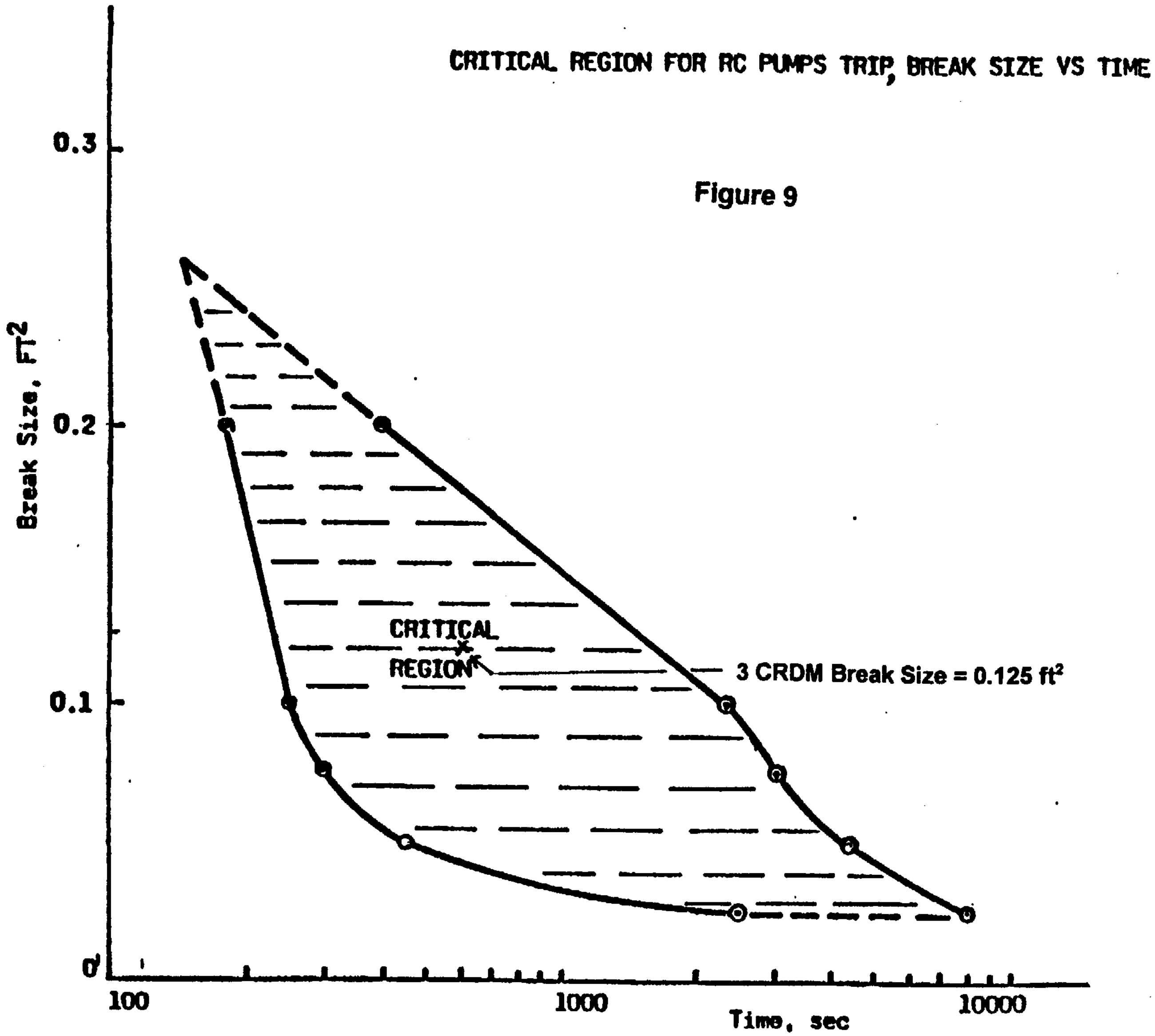

Oconee
Break of Three Control Rod Housings
Reactor Vessel Voiding
voidg-51506 Top of Core
voidg-55001 Top of RV
Void Fraction
Time (s)
0
0.2
0.4
0.6
0.8
1
0
1000
2000

Figure 8


CRITICAL REGION FOR RC PUMPS TRIP, BREAK SIZE VS TIME
Figure 9
Break Size, FT²
0.3
0.2
0.1
0
CRITICAL
REGION
3 CRDM Break Size = 0.125 ft²
100
1000
10000
Time, sec

Oconee

Break of Three Control Rod Housings

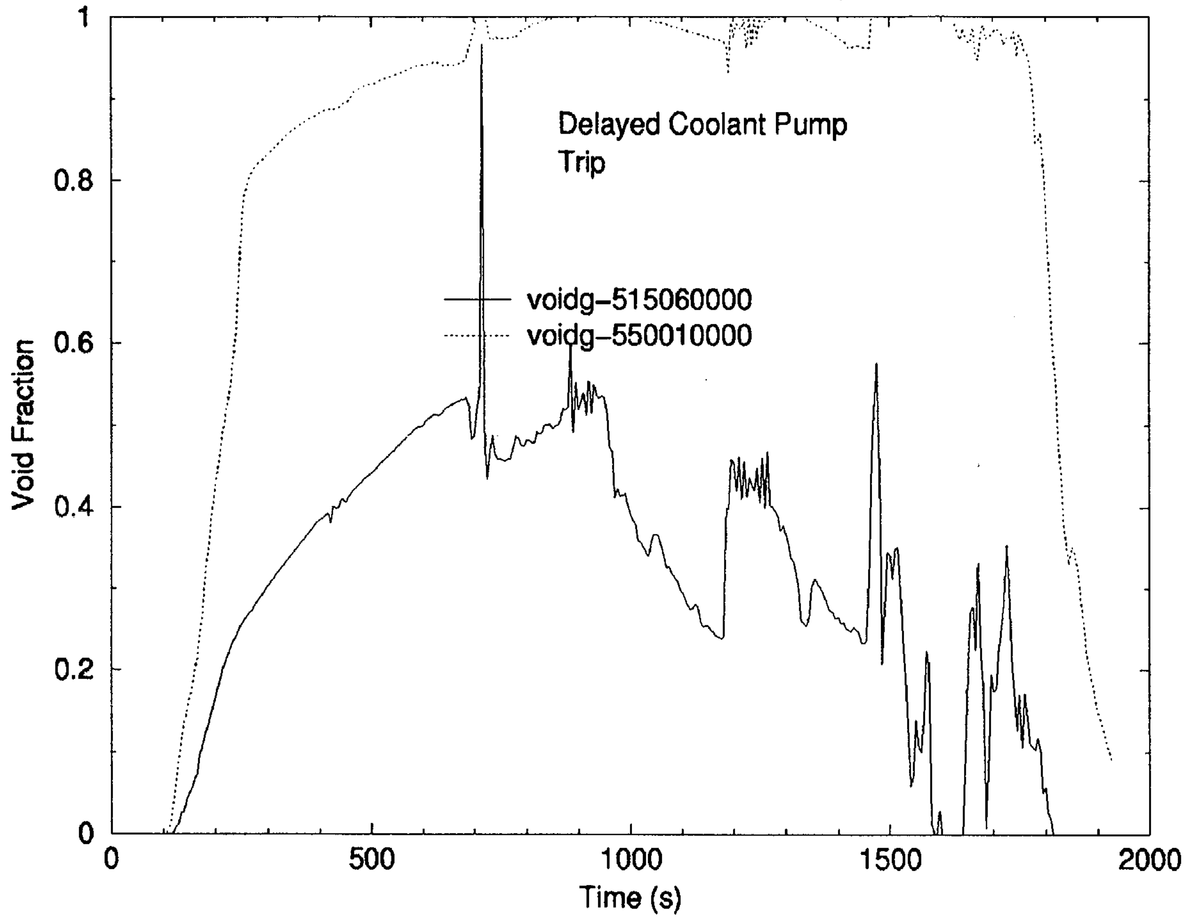


Figure 10

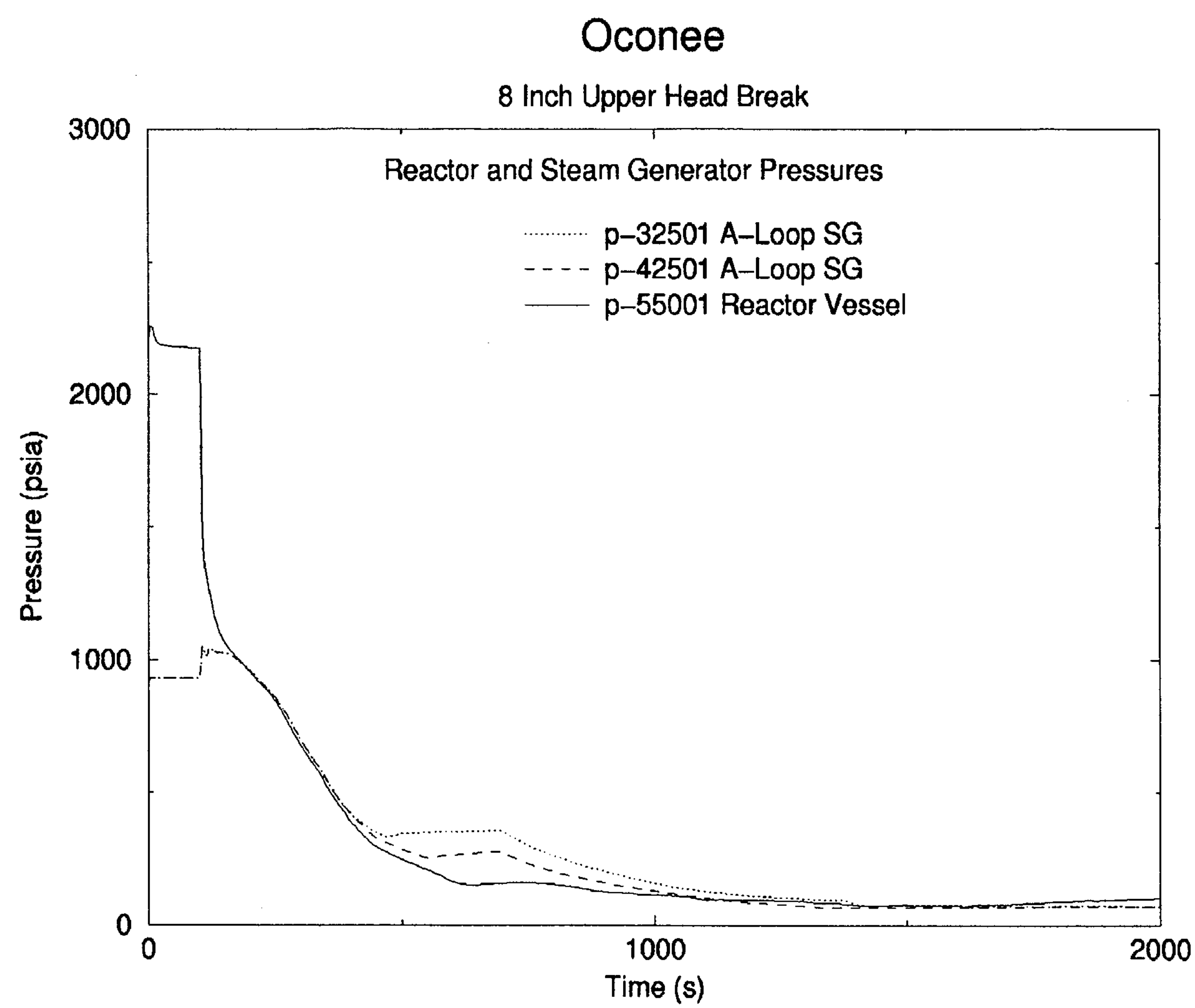

Oconee
8 Inch Upper Head Break
Reactor and Steam Generator Pressures
p–32501 A–Loop SG
p–42501 A–Loop SG
p–55001 Reactor Vessel
3000
2000
1000
0
Pressure (psia)
0
1000
2000
Time (s)

Figure 11

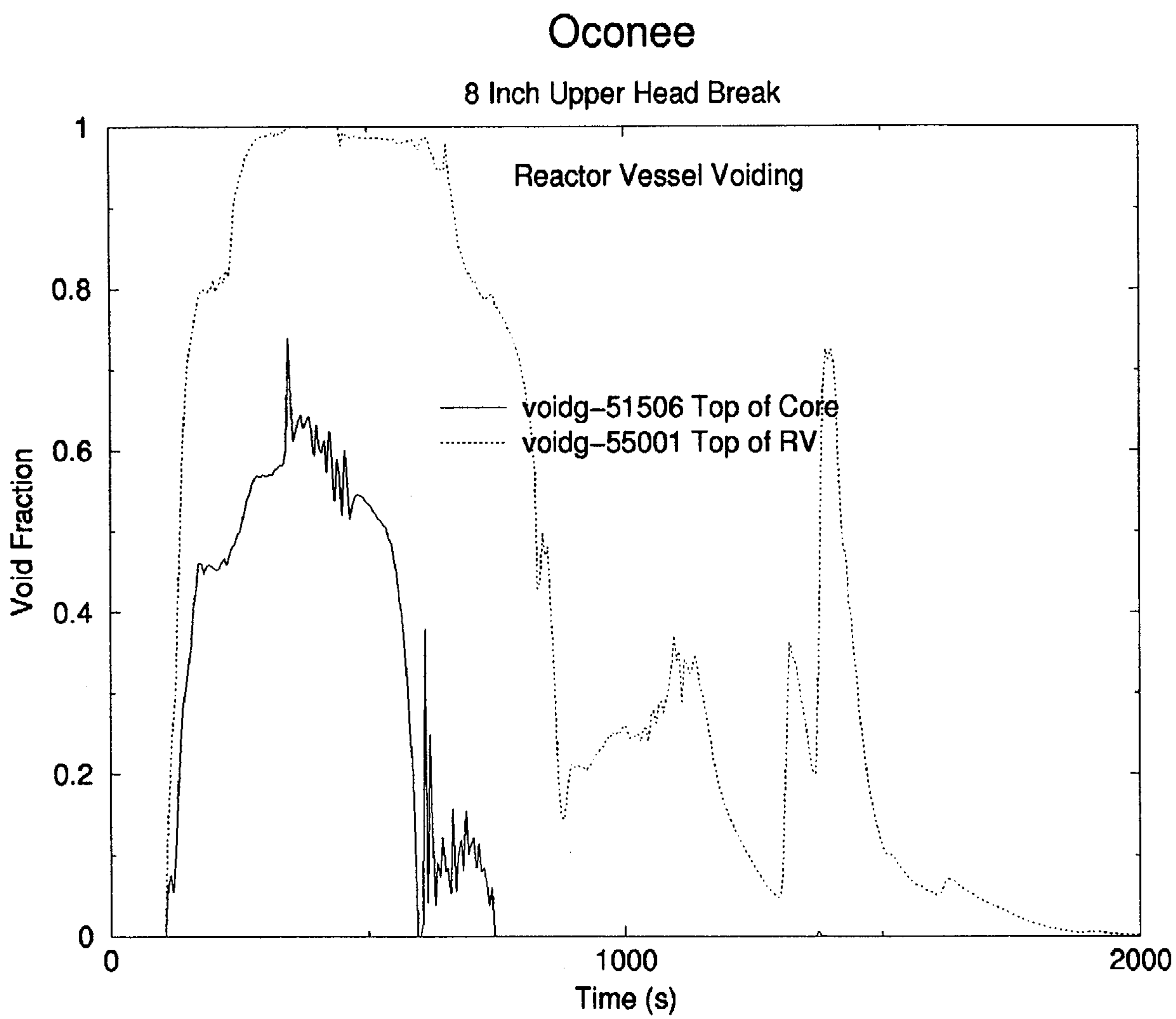

Oconee
8 Inch Upper Head Break
Reactor Vessel Voiding
voidg–51506 Top of Core
voidg–55001 Top of RV
Void Fraction
Time (s)
0
0.2
0.4
0.6
0.8
1
0
1000
2000

Figure 12

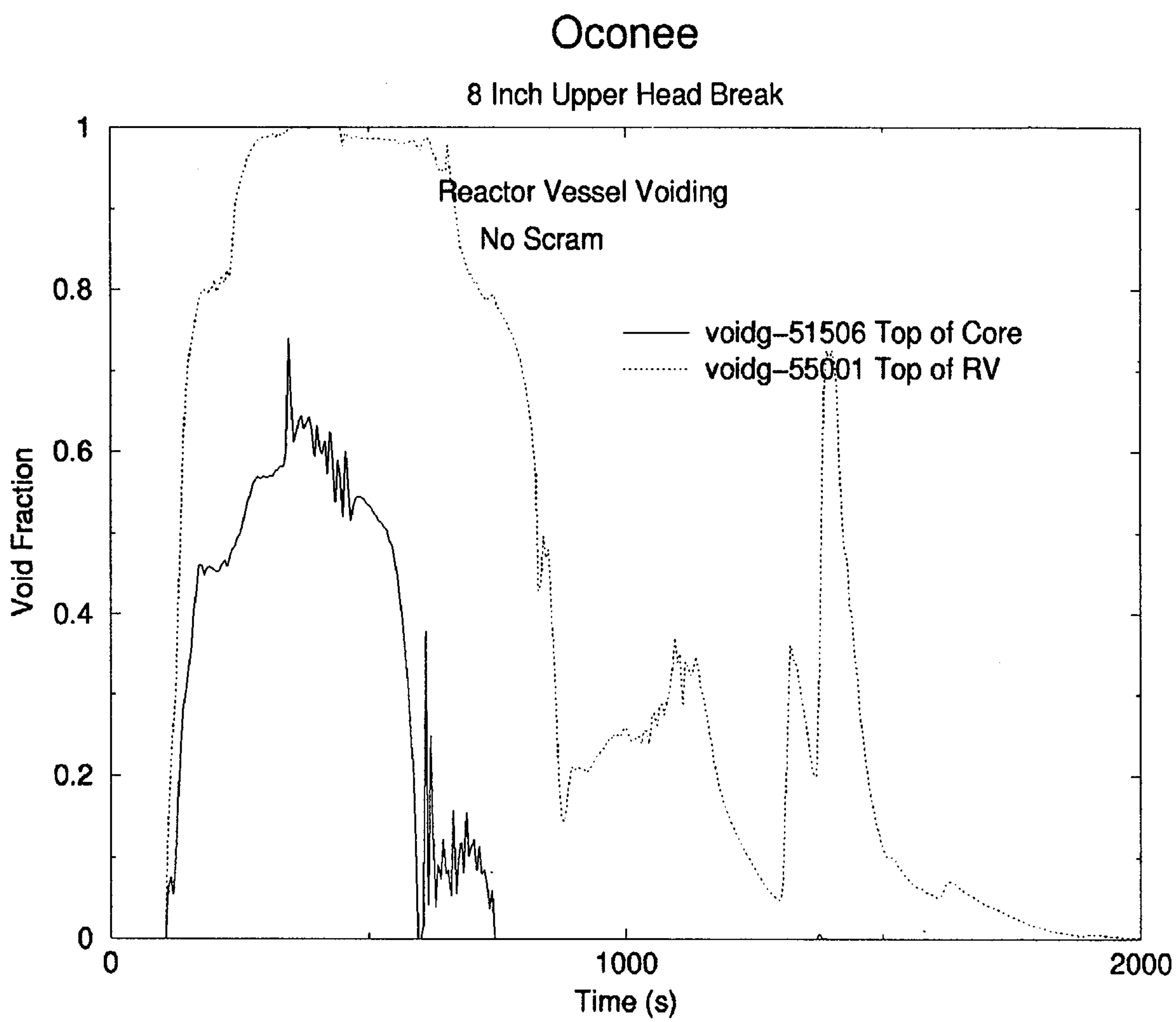

Oconee
8 Inch Upper Head Break
Reactor Vessel Voiding
No Scram
voidg-51506 Top of Core
voidg-55001 Top of RV
Void Fraction
Time (s)
0
0.2
0.4
0.6
0.8
1
0
1000
2000

Figure 13

Oconee

8 Inch Upper Head Break

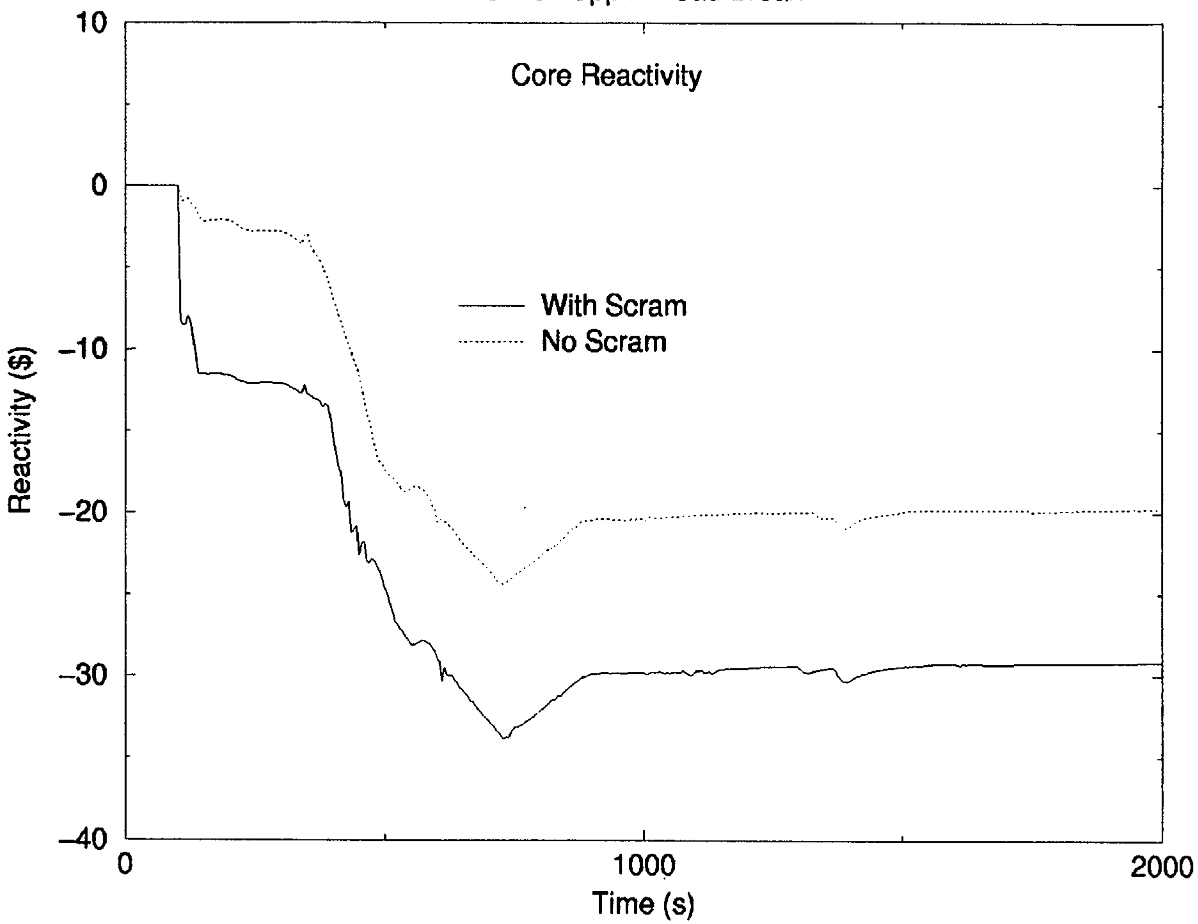


Figure 14

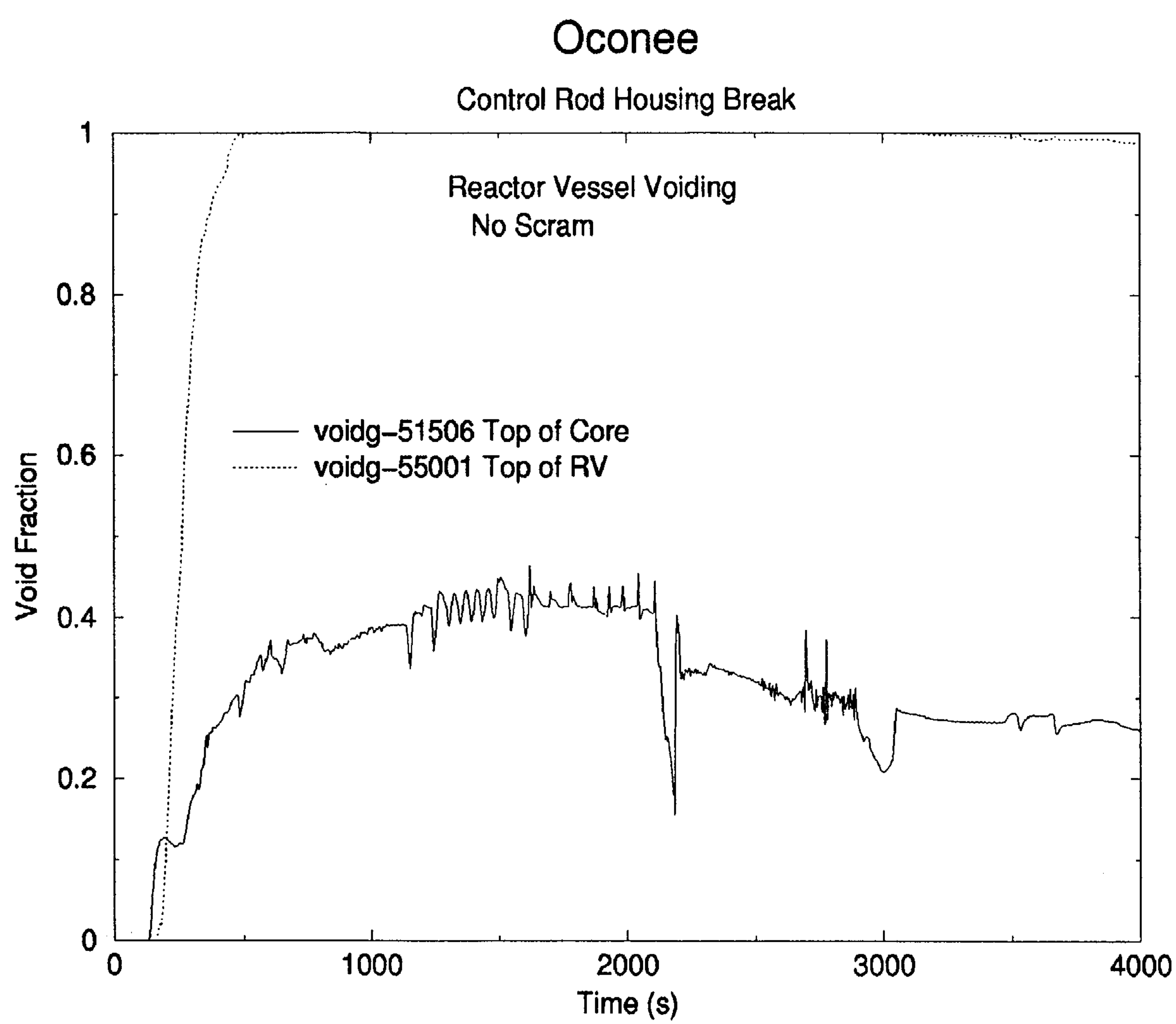

Oconee
Control Rod Housing Break
Reactor Vessel Voiding
No Scram
voidg-51506 Top of Core
voidg-55001 Top of RV
Void Fraction
Time (s)
0
0.2
0.4
0.6
0.8
1
0
1000
2000
3000
4000

Figure 15

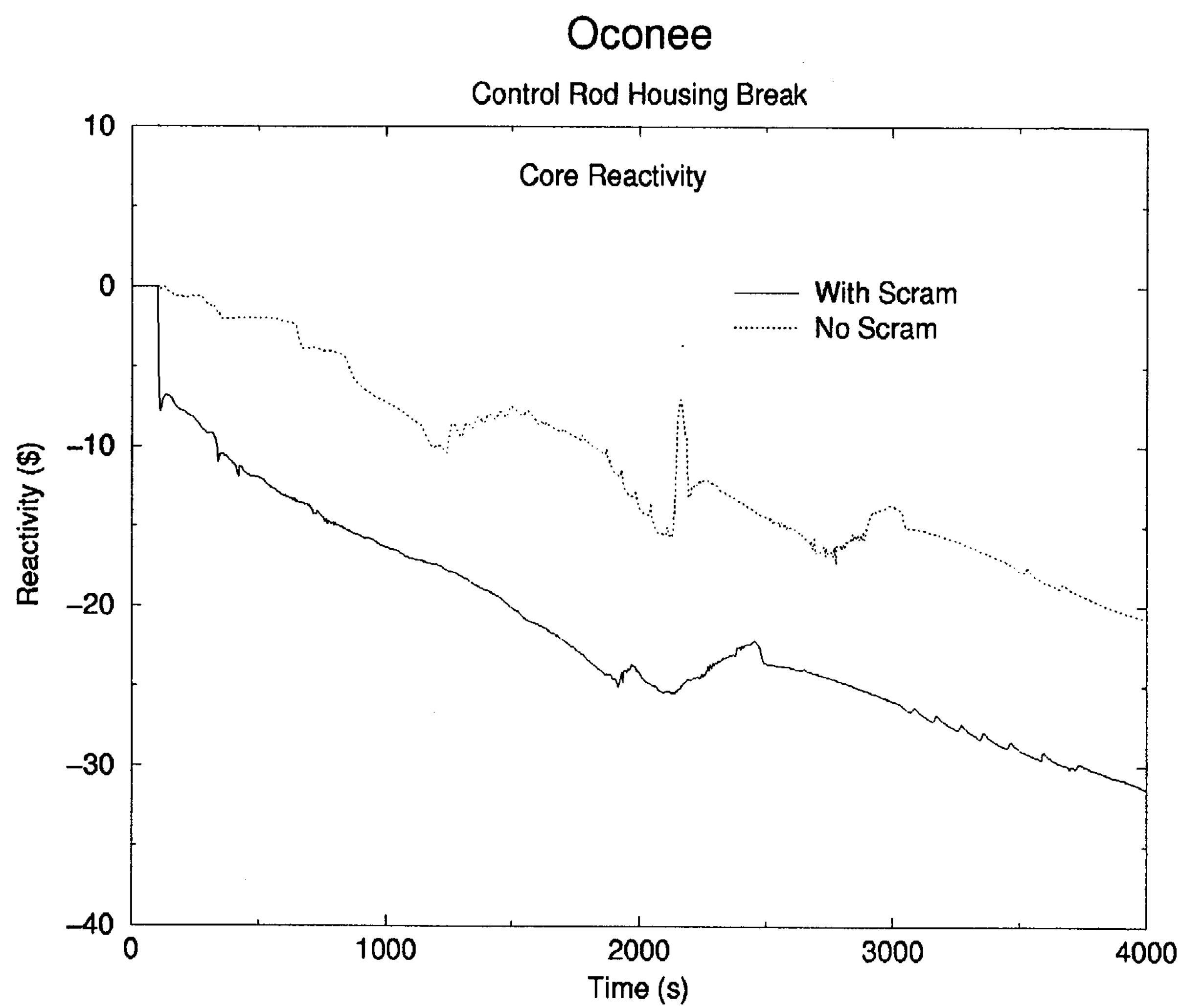

Oconee
Control Rod Housing Break
Core Reactivity
With Scram
No Scram
Reactivity ($)
Time (s)
10
0
-10
-20
-30
-40
0
1000
2000
3000
4000

Figure 16

Oconee

2.765 Inch HL Break vs. CRDM Housing Break

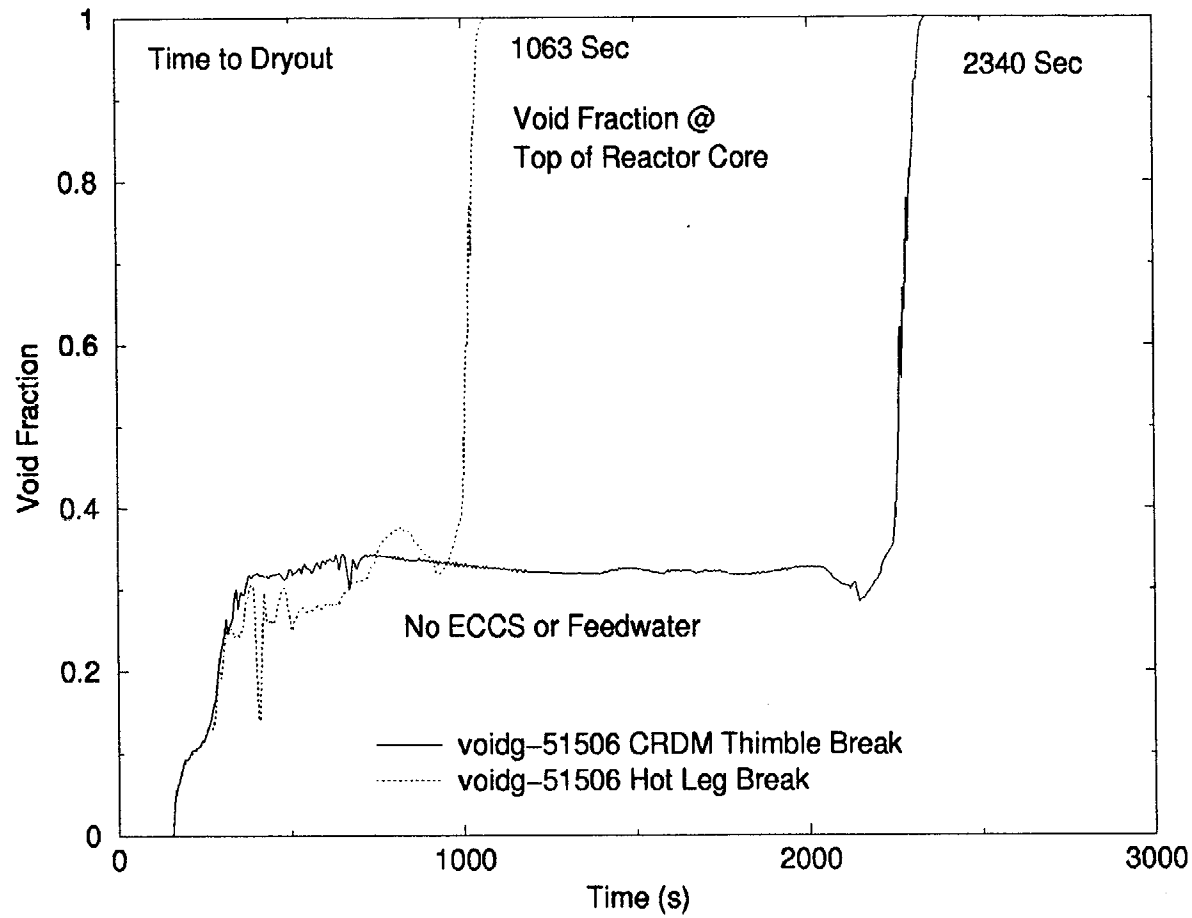


Figure 17

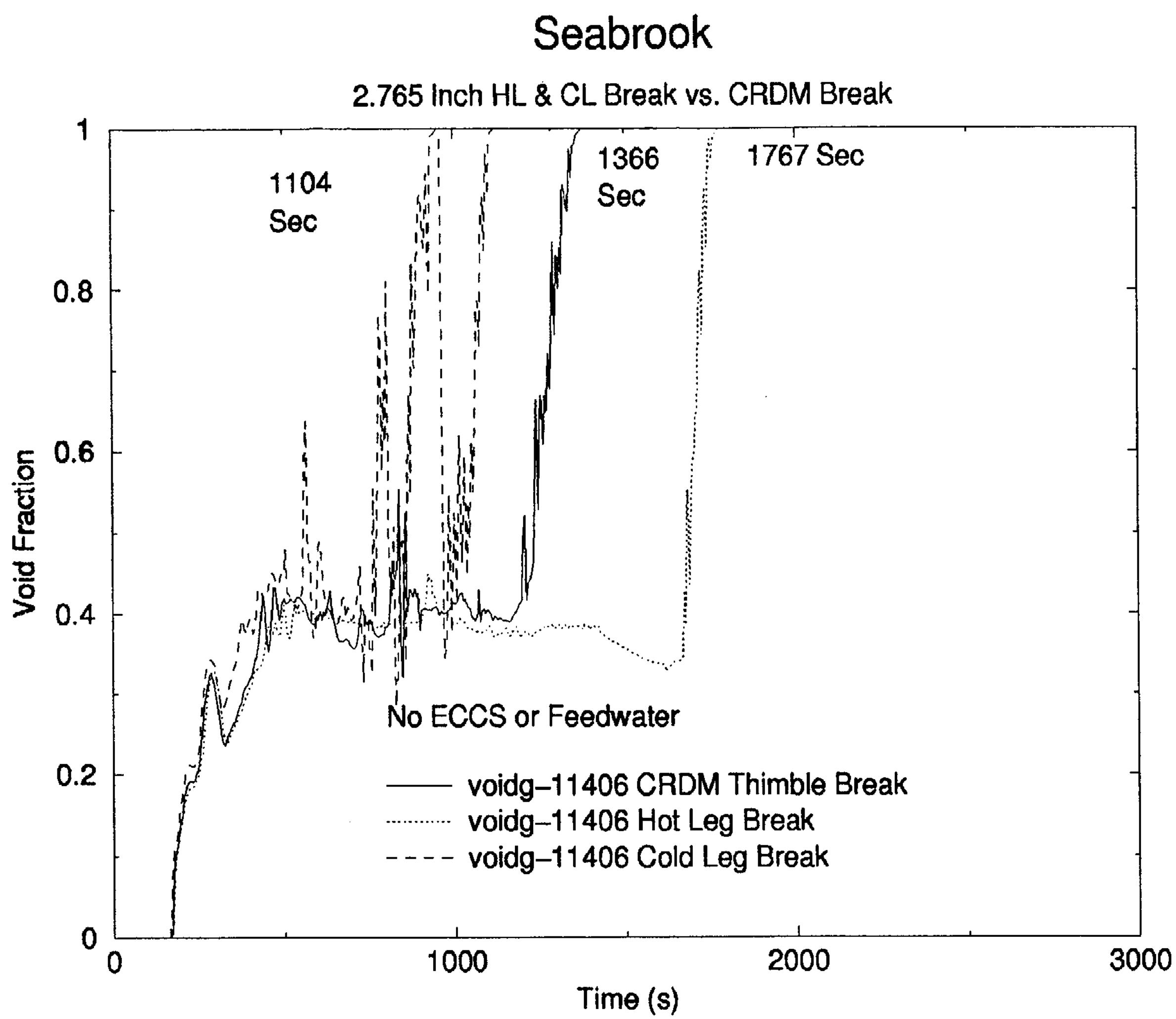

Seabrook
2.765 Inch HL & CL Break vs. CRDM Break
1104 Sec
1366 Sec
1767 Sec
No ECCS or Feedwater
voidg–11406 CRDM Thimble Break
voidg–11406 Hot Leg Break
voidg–11406 Cold Leg Break
Void Fraction
Time (s)
0
0.2
0.4
0.6
0.8
1
1000
2000
3000

Figure 18

ANO–2

2.765 Inch HL Break vs. CRDM Break

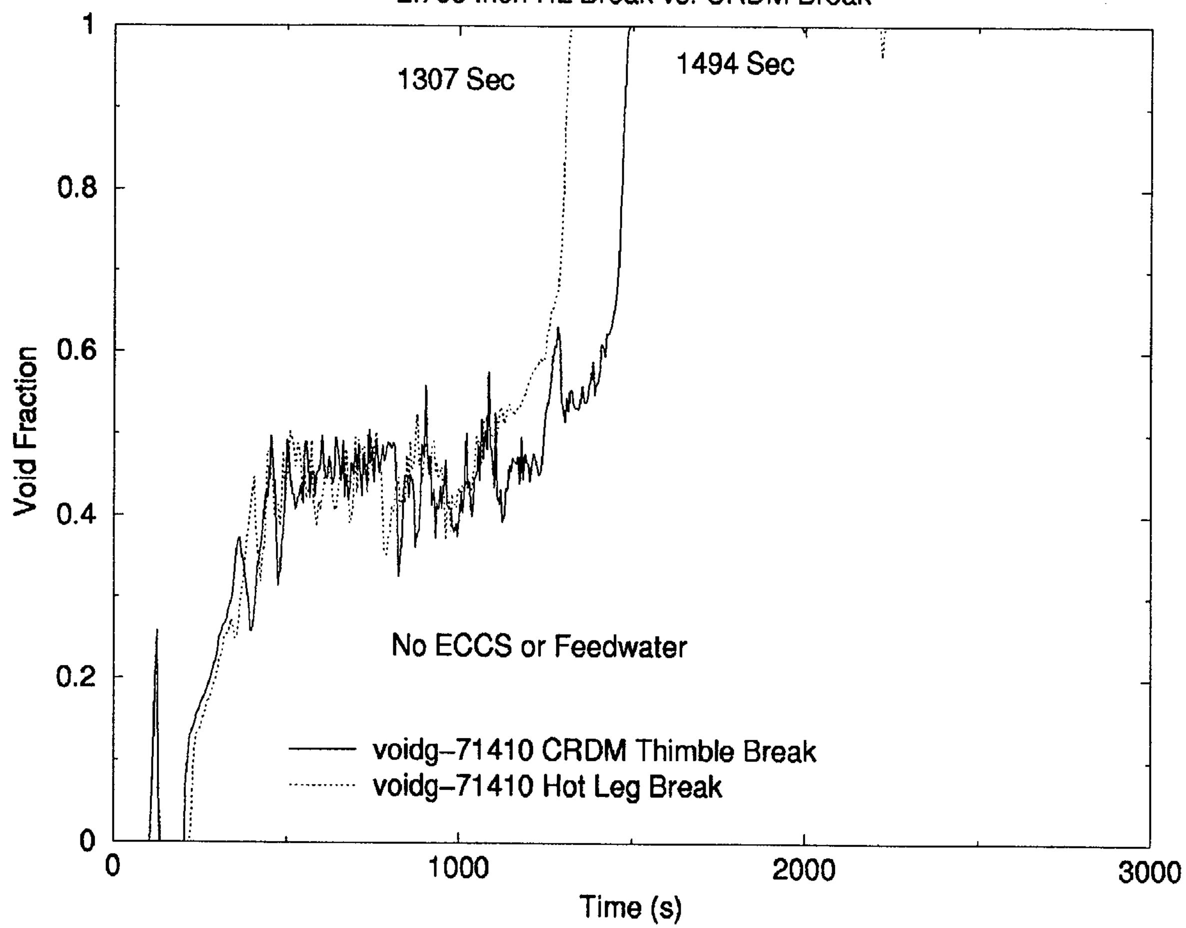


Figure 19

Reference C

Control Rod Drive Mechanism Operation

The control rod drive mechanism (CRDM) is an electromechnical device. During normal operation the drive mechanism is used to raise, lower, or maintain control rod position within the reactor in response to electrical signals from the control rod drive motor control system. The control system provides a sequentially programed dc input to the four-pole, reluctance-type drive motor to produce a rotating magnetic field for the rotor assembly. The rotor assembly is split so that when power is applied to the stator, the rotor assembly arms pivot to mechanically engage the roller nuts with the lead screw threads. When electric power is applied to the electric motor, it causes the operating mechanism to engage the lead screw of the control rod. The rotation of the operating mechanism causes the leadscrew motion. The electric motor drive is designed to trip whenever electric power is removed from it. This causes disengagement of the operating mechanism from the leadscew and the control rods to fall under gravity into the reactor core. This is known as a reactor trip.

The control rod indication system is an integral part of the control rod drive housing and provides absolute position indication by the use of reed switches. In addition to providing indication, these switches also provide control, limit, and alarm function capability for the control system in the control room.

The CRDM consists of a motor tube which acts as the pressure boundary and houses the leadscrew, the leadscrew rotor assembly, and a snubber assembly. The top end of the motor tube is sealed by a closure and vent assembly. The motor stator is mounted externally and surrounds the motor tube. The rotational motion of the rotor assembly is translated to the non-rotating leadscrew coupled to the control rod. The leadscrew is driven by separating roller nut assemblies attached to segment arms which are rotated magnetically by the motor stator outside the motor tube. Current flow through the stator windings establishes a magnetic field which causes the separating roller nut assembly arms to close and engage the leadscrew. When current is removed from the stator, the loss of the magnetic field allows mechanical springs to force the segment arms apart disengaging the roller nut halves from the leadscrew.

The control rod drive mechanism is designed to "trip" whenever power to the stator is interrupted, due to a transient, such as a small break Loss of Coolant Accident (SBLOCA). When the drive mechanisms are required to respond to a trip signal, the action of the control rod drive system and the drive mechanism shall result in a positive, nonreversible initiation of the trip function. The trip command has priority over all other commands. The CRDM system is required to trip the CRDM whenever it receives an automatic trip command signal from the reactor protection system (RPS) or a manual trip command signal from the operator. During a power loss, the rotor assembly segment arms pivot, releasing the mechanical contact between the roller nut and the leadscrew. The lead screw and control rod are then pulled into the reactor core to the full-in positions by gravity. During the free fall condition, coolant is allowed to pass from the reactor head area into the motor tube housing, through the ball check valves in the lead screw. This prevents the formation of a low-pressure area that could affect rod drop times. The hydraulic snubber assembly, within the motor tube housing, decelerates the moving control rod assembly (CRA) to a low speed just before it reaches the CRA full-in position. The final deceleration energy is absorbed by the belleville spring assembly. The CRDM system is designed to provide safe shutdown and to provide for positive and safe reactor shutdown from all operating and transient load conditions without damage to the reactor.

Reference D

May 3, 2002

Mr. Howard Bergendahl
Vice President - Nuclear
FirstEnergy Nuclear Operating Company
Davis-Besse Nuclear Power Station
5501 North State Route 2
Oak Harbor, OH 43449-9760

SUBJECT: DAVIS-BESSE NUCLEAR POWER STATION
NRC AUGMENTED INSPECTION TEAM - DEGRADATION OF THE
REACTOR PRESSURE VESSEL HEAD - REPORT NO. 50-346/02-03(DRS)

Dear Mr. Bergendahl:

Your staff provided information to the NRC between March 6 and 10, 2002, concerning the identification of a large cavity in the reactor vessel head adjacent to a control rod drive nozzle. On March 13, 2002, the NRC issued a Confirmatory Action Letter outlining specific actions your staff are expected to take in response to this event. One of those actions is obtaining NRC approval prior to restart of the Davis-Besse plant.

On March 12, 2002, the NRC dispatched an Augmented Inspection Team (AIT) to the Davis-Besse site in accordance with NRC Management Directive 8.3, "NRC Incident Investigation Program." The AIT was chartered to determine the facts and circumstances related to the significant degradation of the reactor vessel head pressure boundary material. The AIT developed a sequence of events, interviewed plant personnel, collected and analyzed factual information relevant to the degraded condition and conducted visual inspections of the reactor vessel head. The enclosed report provides the AIT findings which were summarized for you and your staff during a public exit meeting on April 5, 2002.

The cavity in the reactor vessel head was discovered during maintenance activities for problems found during inspections conducted pursuant to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles." The degraded area covers approximately 30 square inches where the thick low-alloy structural steel was corroded away, leaving only the thin stainless steel cladding layer as a pressure boundary for the reactor coolant system. This represents a loss of the reactor vessel's pressure retaining design function, since the cladding was not considered as pressure boundary material in the structural design of the reactor pressure vessel. While the cladding did provide a pressure retaining capability during reactor operations, the identified degradation represents an unacceptable reduction in the margin of safety of one of the three principal fission product barriers at the Davis-Besse Nuclear Power Station.

The AIT concluded that the cavity was caused by boric acid corrosion from leaks through the control rod drive nozzles in the reactor vessel. These leaks were caused by primary water stress corrosion cracking of the nozzle material leading to a through-wall crack and corrosion of low alloy steel that went undetected for an extended period of time. The boric acid corrosion control program at the site included both cleaning and inspection requirements, but was not effectively implemented to detect the leakage and prevent the significant corrosion of the reactor vessel head over a period of years. Similarly on several occasions, maintenance and corrective action activities failed to detect and address the indications in the containment that the significant corrosion of the reactor vessel head was occurring. The NRC views these as missed opportunities to identify and correct this significant degradation to the reactor pressure vessel head.

The AIT did not address the verification of compliance with NRC rules and regulations, provide recommendations for enforcement actions, or assess the risk significance of this issue. A followup special inspection effort will be scheduled in the near future to pursue these aspects of the regulatory process.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

/RA by J. L. Caldwell for/

J. E. Dyer
Regional Administrator

Enclosure: NRC Augmented Inspection Report
No. 50-346/02-03(DRS)

cc w/encl: B. Saunders, President - FENOC
Plant Manager
Manager - Regulatory Affairs
M. O'Reilly, FirstEnergy
Ohio State Liaison Officer
R. Owen, Ohio Department of Health
Public Utilities Commission of Ohio

control program at the site included both cleaning and inspection requirements, but was not effectively implemented to detect the leakage and prevent the significant corrosion of the reactor vessel head over a period of years. Similarly on several occasions, maintenance and corrective action activities failed to detect and address the indications in the containment that the significant corrosion of the reactor vessel head was occurring. The NRC views these as missed opportunities to identify and correct this significant degradation to the reactor pressure vessel head.

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Sincerely,

J. E. Dyer
Regional Administrator

Enclosure: NRC Augmented Inspection Report
No. 50-346/02-03(DRS)

cc w/encl: B. Saunders, President - FENOC
Plant Manager
Manager - Regulatory Affairs
M. O'Reilly, FirstEnergy
Ohio State Liaison Officer
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-346
License No:	NPF-3
Report No:	50-346/02-03
Licensee:	FirstEnergy Nuclear Operating Company
Facility:	Davis-Besse Nuclear Power Station
Location:	5501 North State Route 2 Oak Harbor, OH 43449
Dates:	March 12 - April 5, 2002
Team Leader:	R. Gardner, Engineering Branch Chief, DRS
Inspectors:	J. Davis, Sr. Materials Engineer, RES M. Holmberg, Sr. Reactor Inspector, DRS J. Gavula, Sr. Reactor Inspector, DRS D. Simpkins, Resident Inspector, Davis-Besse, DRP
Approved by:	John A. Grobe, Director Division of Reactor Safety

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000346-02-03, on 03/12-04/05/2002, FirstEnergy Nuclear Operating Company, Davis-Besse Nuclear Power Station. Augmented Inspection Team.

This report covers a 3-week inspection by an NRC Augmented Inspection Team for the substantial loss of material from the reactor pressure vessel head.

- On March 5 and 6, 2002, workers at Davis-Besse were repairing control rod drive penetration Nozzle 3, following the identification of cracks detected through inspections performed pursuant to NRC Bulletin 2002-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles." The workers discovered a large cavity, a significant loss of metal adjacent to the control rod drive nozzle in the reactor vessel head, that apparently resulted from boric acid corrosion of the reactor vessel head due to leakage from the cracks in Nozzle 3.

- The cracks in the control rod drive nozzles were apparently due to primary water stress corrosion cracking of the Alloy 600 nozzle material. This type of cracking in this type of material has been identified at other facilities. However, the cracks at Davis-Besse appear to have initiated earlier than expected due to fabrication issues and plant operating conditions.

- The Davis-Besse staff, through their boric acid corrosion control program, did not clean and inspect the reactor vessel head sufficiently to identify the leakage due to nozzle cracking, nor the degradation of pressure boundary material.

- The apparent rate of boric acid corrosion was consistent with certain industry data. However, the corrosion rate used by the Babcock and Wilcox Owners Group, in their past assessment of potential head degradation associated with nozzle cracking, was significantly less than the apparent corrosion rate at Davis-Besse.

- The Davis-Besse staff missed several opportunities to identify the boric acid corrosion of the reactor vessel head at an earlier time. These opportunities involved the failure to identify the source of corrosion products that had accumulated on the containment air cooler fins, deposited on the containment radiation element filters, and noted as emanating from the inspection ports on the reactor vessel head service structure.

Report Details

1.0 BACKGROUND AND EVENT OVERVIEW

On March 6, 2002, Davis-Besse personnel notified the NRC of degradation to the reactor vessel head material adjacent to a control rod drive nozzle. The NRC issued a Confirmatory Action Letter on March 13, 2002. An Augmented Inspection Team (AIT) was chartered in Attachment A to determine the facts and circumstances related to the degradation of the reactor vessel head pressure boundary material, and to identify any precursor indications of this condition. The AIT developed a sequence of events, interviewed plant personnel, collected and analyzed factual information and evidence relevant to the reactor vessel head material loss, and conducted visual inspections of the reactor vessel head. The inspection was conducted in accordance with the AIT Charter, NRC Inspection Procedure 93800, "Augmented Inspection Team," and NRC Management Directive 8.3, "NRC Incident Investigation Program." In accordance with NRC procedures, the AIT charter did not include the verification of compliance with NRC rules and regulations, the recommendation of enforcement actions, nor the determination of risk significance for this issue. A public exit was conducted on April 5, 2002, using the presentation material in Attachment B.

1.1 Description of Reactor Vessel Head and Penetration Nozzles

Davis-Besse Nuclear Power Station is a two-loop pressurized water reactor designed by Babcock and Wilcox (B&W). The Davis-Besse reactor vessel has a torispherical shaped closure head constructed from low alloy steel (American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), SA-533, Grade B, Class 1), with approximately an 87-inch inside crown radius, 6.63 inches thick. The inside surface of the vessel head is clad with Type 308 and 308L stainless steel using a 6-wire submerged arc welding process. The cladding is provided for corrosion resistance and is not credited as pressure boundary material.

There are 69 vessel head penetration nozzles arranged in a rectangular pattern, with a center-to-center distance of approximately 12 inches, and are numbered sequentially starting at the center and progressing concentrically outward. The nozzles are fabricated from Alloy 600 tubes, with an outside diameter of approximately 4.00 inches and a wall thickness of 0.65 inches. The nozzles vary in length, depending on the location on the vessel head, from approximately 30 inches in the center to approximately 50 inches on the periphery. This includes a flange at the top for connecting to the control rod drive mechanism (CRDM) housings. Refer to Slide 5 in Attachment B for a diagram of the CRDM configuration. The nozzles extend through 4.00 inch bores in the vessel head, and are welded to the head with a J-groove weld at the inner surface of the head using Alloy 82 and 182 weld material. Refer to Slide 7 in Attachment B for a diagram of the CRDM nozzle.

The service structure is an enclosure attached to the reactor vessel head, approximately 18 feet high and 10 feet in diameter. This structure stabilizes and houses the CRDMs and contains a horizontal layer of metallic reflective insulation approximately 2 inches above the top of the vessel head. The CRDM nozzles welded to the vessel head pass through the insulation layer and attach to the CRDM housings with bolted flanges. These flanges are located about 9 inches above the horizontal insulation layer.

1.2 Sequence of Events: Discovery of Reactor Vessel Head Degradation

On February 16, 2002, the Davis-Besse facility began its 13th refueling outage (13 RFO), which included inspections of the CRDM nozzles in accordance with NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles." On February 27, 2002, the licensee notified the NRC that CRDM Nozzles 1, 2 and 3 exhibited axial through-wall indications. The licensee decided to repair these three nozzles plus two other nozzles which had crack indications that did not appear to be through-wall.

On March 5, 2002, the licensee began repair work on CRDM Nozzle 3. The repair process included roll expansion of the CRDM nozzle material into the surrounding reactor vessel head material, followed by machining along the axis of the CRDM nozzle from the bottom to a point above the cracks in the nozzle material. After machining up past the J-groove weld, the machine unexpectedly rotated 15 degrees. The machining process was stopped and the machining tool was removed. Subsequent investigation identified that CRDM Nozzle 3 had tilted and was resting against an adjacent nozzle flange, which indicated a loss of some vessel head material.

On March 6, 2002, the licensee began an investigation to identify the cause of the movement by removing the CRDM nozzle. At the same time, activities were underway to remove boric acid residue from the top of the reactor vessel head using high pressure hot water to dissolve the deposits. After removing the boric acid deposits, the licensee identified a large cavity in the head material on the downhill side of CRDM Nozzle 3. In addition, during this same time period, the licensee identified a smaller cavity in the reactor vessel head after machining away the lower portion of Nozzle 2 during repair activities.

2.0 CHARACTERIZATION OF NOZZLE CRACKING AND REACTOR VESSEL HEAD WASTAGE AREAS

2.1 CRDM Nozzle Cracking

In response to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," the licensee ultrasonically examined all 69 CRDM nozzles during the current outage (13 RFO). These examinations were conducted inside the penetration tube from below the vessel head, and data was recorded from at least 1 inch above the J-groove weld down to the lower end of the nozzle. For these examinations, the ultrasonic transducers used were mounted in a blade probe head and setup for time-of-flight-diffraction. The transducer orientation was such that it provided maximum sensitivity for circumferentially oriented cracks near the outside diameter of the tube. Six nozzles were initially identified with crack-like indications using this technique.

For the six nozzles with crack indications a supplemental ultrasonic examination was conducted using a rotating head probe from above the vessel head. This probe head contained several types and angles of transducers designed to maximize the response to cracks oriented in both the circumferential and axial directions. This rotating probe confirmed cracks in five of the six nozzles identified by the blade probe. The cracks in these five nozzles initiated from the outside diameter of the nozzle near the J-groove weld. In three of the nozzles, through-wall axial cracks were identified that traversed the J-groove weld area of the nozzle. In addition, one circumferentially (circ.) oriented crack was identified in Nozzle 2 just above the J-groove weld, that was about 50 percent through-wall in depth. The number and dimensions of nozzle cracks are identified below:

Nozzle Number	Cracks and Orientation	Through-Wall Cracks	Through-Wall Crack Length (inches)	Crack Length Above J-weld (inches)
1	9 Axial	2	1.77 and 3.49	0.0, 0.5
2	8 Axial 1 Circ.	5 None	3.86, 2.71, 2.59, 3.95, 3.04 Not Applicable	0.8, 0.5, 0.5, 1.0, 0.5 Not Applicable
3	4 Axial	2	4.08, 3.84	1.3, 0.8
5	1 Axial	None	Not Applicable	Not Applicable
47	1 Axial	None	Not Applicable	Not Applicable

Although cracking was not identified at Nozzle 46, ultrasonic examinations revealed evidence of possible leakage and minor wastage in the annulus between the nozzle and the vessel head. Because a crack entirely within the J-groove weld could provide a leakage path and would not be detected with ultrasonic techniques, the licensee performed a dye penetrant examination of the J-groove weld. Four rounded indications were found, one 0.13 inches in diameter and three 0.06 inches in diameter. At the conclusion of this inspection, the licensee had not yet confirmed whether these indications were indicative of J-groove weld cracking.

2.2 Reactor Vessel Head Wastage Areas

The cavity adjacent to Nozzle 3 extended downhill toward Nozzle 11 for approximately 5 to 7 inches and was 4 to 5 inches wide. Within this area the 6.63 inch thick low alloy steel head was corroded away leaving only the stainless steel cladding layer on the inside of the reactor vessel head. The remaining cladding layer, ranging in thickness from 0.24 to 0.38 inches, had deflected upward into the cavity approximately 0.12 inches. This cladding layer is designed as a corrosion resistant layer and no credit is taken for the structural or pressure retaining capability of this layer. Therefore, the cavity at Nozzle 3 represented a loss of the design basis structural/pressure retaining boundary for the vessel head.

The cavity sides contained uneven ridges tapering downward, such that the cavity was larger at the outer surface of the head. Additionally, an undercut shelf existed at the downhill end of the cavity near Nozzle 11. An ultrasonic examination was conducted from the inner surface of the head to determine the extent of the cavity near Nozzle 3. This examination found that the cavity potentially had a "debonding" area between the stainless steel cladding layer and the vessel head material which extended for several inches around the cavity. The licensee intended to conduct additional examinations to further quantify the extent of this debonding. Refer to Slides 8 and 9 of Attachment B for a diagram and picture of this cavity.

In addition to the cavity adjacent to Nozzle 3, a comparatively small cavity was identified behind Nozzle 2. This cavity was approximately 1.75 inches wide and 0.25 inches deep. The licensee determined that the cavity extended from the top of the weld to the top of the vessel behind Nozzle 2 (approximately 4.2 inches). Refer to Slide 10 of Attachment B for a diagram of this area. The licensee removed Nozzle 2 to provide a more detailed characterization of this cavity after the AIT inspection.

3.0 PROBABLE CAUSE OF NOZZLE CRACKING AND HEAD WASTAGE

3.1 Probable Cause for Nozzle Cracking

For the five penetration nozzles with indications characterized as cracks (Section 2.1), four of these nozzles (Nos. 1, 2, 3, 5) were made from material heat No. M3935 manufactured by B&W Tubular Products. This same heat of tube material was found to have cracks in 14 of 68 penetrations used at Oconee Unit 3. This cracking was confirmed to be primary water stress corrosion cracking (PWSCC) based on analysis of cracked nozzles removed from Oconee Units 2 and 3 (these units also have a vessel head designed and constructed by B&W). Therefore, based on the observed susceptible heat of nozzle material under a similar environment, the AIT concluded that the Davis-Besse nozzle cracking was likely caused by PWSCC.

3.1.1 Factors Affecting Primary Water Stress Corrosion Cracking of Nozzles

Cracking of Inconel Alloy 600 penetration nozzle materials near the J-groove weld has been observed at several pressurized water reactors. The area of the J-groove weld on the nozzle is susceptible to PWSCC as discussed in NRC Generic Letter (GL) 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," and in NRC Information Notice 2001-05, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles at Oconee Nuclear Station, Unit 3." The susceptibility of a nozzle to cracking has been reviewed and documented in NUREG/CR-6245, "Assessment of Pressurized Water Reactor Control Rod Drive Mechanism Nozzle Cracking." The susceptibility of a nozzle to PWSCC may be dependant on material, operating temperature, time, environment and residual stress. Because the operating environment of domestic pressurized water reactors is similar, the susceptibility of a particular nozzle to cracking may be dependant upon time, temperature, material microstructure and residual tensile stress. Thus, a particular heat of Alloy 600 used to fabricate a penetration nozzle may be more likely to experience cracking as each of these variables is increased (e.g., longer service time, higher operating temperatures, or a higher residual tensile stress). For the J-groove weld connecting the nozzle to the vessel head, a high residual tensile hoop stress is developed in the nozzle because of weld shrinkage. The magnitude of this residual tensile stress can range up to the yield strength of the material.

Crack initiation for PWSCC is strongly dependant on temperature (NUREG/CR-6245). The 605°F operating temperature at Davis-Besse is higher than the other B&W plants (typically 602°F). This higher operating temperature may have shortened the required operating time required to initiate cracking in the nozzles at Davis-Besse relative to other B&W designed plants.

Once a crack is formed (at a given temperature and environment) in a nozzle, the speed of crack propagation may be influenced by the tensile hoop stress induced from plant operating pressure and residual tensile hoop stresses induced by welding. As an axial crack in the nozzle progresses in length above the J-groove weld, welding induced residual tensile stress decreases rapidly, leaving only the operating pressure hoop stresses to extend the crack length. This results in slower crack growth as a crack increases in length above the J-weld. Therefore, the cracks identified in Section 2.1 which extend for the greatest distance above the J-groove weld are potentially the oldest cracks.

3.1.2 CRDM Nozzle Materials and Contributing Factors

Of the 69 Alloy 600 nozzles at Davis-Besse, 60 were manufactured by B&W Tubular Products and 9 were fabricated by Huntington Alloys. The nozzles are attached to the vessel head with an Alloy 82/182 "butter" and Alloy 82/182 J-groove weld. The specific method of fabricating the nozzle tubes was not recorded, but it would include rotary piercing or extruding over a mandrel followed by a mill anneal. The mill annealing heat treatment temperature should be in the range of 1850°F to 1950°F to put carbon into solution so that the carbides will precipitate at the grain boundaries during cooling. This heat treatment also redistributes chromium in the region of the grain boundaries. However, based on review of production records, the nozzles for all B&W plants were mill annealed in the temperature range of 1600°F to 1700°F. This lower temperature can increase susceptibility to primary water stress corrosion cracking.

As stated above, four of the Davis-Besse nozzles (Nos. 1, 2, 3, 5) exhibiting cracks were fabricated from material heat No. M3935 manufactured by B&W Tubular Products. This nozzle material heat had the highest yield strength (48,500 pounds per square inch) of the four material heats used to fabricate Davis-Besse head penetrations. It appears that this heat of Alloy 600 is more susceptible to primary water stress corrosion cracking than other heats of Alloy 600 used for B&W penetration tubes. However, the Owners Groups for B&W, Westinghouse, and Combustion Engineering have not been able to establish a definitive correlation between the yield strength and susceptibility to primary water stress corrosion cracking. Penetration tube 47 was also manufactured by B&W Tubular Products (heat number C2649-1) and contained a small crack below the J-Groove weld. This heat of material had the second highest yield strength (44,900 pounds per square inch). An additional factor affecting the material's yield stress was the straightening process used during manufacturing. This process will work harden the outside diameter of the nozzle resulting in the outside diameter yield stress being substantially above inside diameter yield stress.

3.2 Probable Cause for Vessel Head Wastage Cavities

Corrosion experiments (discussed in Section 3.2.1.2) simulating a cracked nozzle have confirmed that corrosion rates in excess of 2 inches per year are possible in low alloy steel. Nozzle 3 contained two through-wall axial cracks, which traversed the J-groove weld. The longest of these two cracks extended for approximately 1.3 inches above the J-groove weld. This crack would likely be the oldest crack in this nozzle as discussed in Section 3.1.1. The crack was on the downhill side of Nozzle 3 in direct alignment with the long dimension of the cavity. Therefore, the AIT concluded that the cavity observed on Nozzle 3 was associated with boric acid corrosion from crack induced leakage at this nozzle. Further, the AIT concluded, based on corrosion products observed on the head and in the containment air coolers and radiation element filters, that the corrosion process had been in progress for at least 4 years.

For Nozzle 2, the crack with the longest dimension above the J-weld was also located in the same area as the observed area of metal loss behind this nozzle. Again, the AIT considered that the metal loss was caused by boric acid corrosion from crack induced leakage at this nozzle.

3.2.1 Boric Acid Corrosion Mechanism

Pressurized water reactors use boric acid in the reactor coolant as one means of controlling the nuclear reaction rate. The levels of boric acid in the reactor coolant can range up to 2000 parts per million, which is generally not corrosive to materials used in the reactor plant. However, if boric acid is allowed to reach a concentrated solution it can become very corrosive to carbon steel components. The NRC issued GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR [Pressurized Water Reactor] Plants," in March of 1988. The Generic Letter was in response to several industry incidents where concentrated boric acid solution, formed by evaporation of water from leaking reactor coolant, corroded reactor coolant pressure boundary components. The Generic Letter requested that licensees implement a program consisting of systematic measures to ensure that the reactor coolant pressure boundary would have an extremely low probability of abnormal leakage, rapidly propagating failure, or gross rupture.

3.2.1.1 Boric Acid Corrosion Processes

Compounds of boron can develop from the precipitation of boric acid from solution. Boric acid (H_3BO_3) and boric oxide (B_2O_3) can exist in a solid or molten state. The solid form of boric acid produced during evaporation depends on the rate of evaporation with faster evaporation creating smaller particles. When a boric acid solution comes in contact with boric acid crystals, larger crystals tend to form. It is also possible to form a salt tree when previously precipitated solids form a porous structure that can wick more solution to the vapor phase interface.

Boric acid solution that leaks onto the vessel head will cause the water to flash to steam, leaving behind white, popcorn-like boric acid crystals. This form of boric acid crystals is relatively easy to remove after the reactor is cooled down to ambient temperature. Dry, white, powdery boric acid crystals on the reactor vessel head have been found to be relatively benign while the reactor head is at operating temperatures. Although some darkening of the boric acid crystals may occur with age, brown or rust colored boric acid is a strong indication that corrosion has occurred and a problem potentially exists.

Above 302°F, boric acid begins to dehydrate to form boric oxide:

$$2\ H_3BO_3 \Rightarrow B_2O_3 + 3H_2O$$

The final condition of the mixture of boric acid and boric oxide is site specific, depending on the relative quantities of each component and the amount of flow of boric acid, the porosity created by steam escaping, and the presence of impurities such as iron oxide. Boric oxide begins to soften at 617°F and becomes highly viscous at 842°F.

As boric acid that is not converted to the oxide is heated above 365°F, it may become a viscous fluid (A. S. Myerson, Handbook of Industrial Crystallization, Butterworth-Heinemann, Boston, 1993), conforming to the surrounding geometry under the influence of gravity. Molten boric acid can contain between 8 and 14 percent water and can be highly corrosive under some conditions (U. Gurbuz Beker and N. Bulutcu, "A New Process to Produce Granular Boric Oxide by High Temperature Dehydration of Boric Acid in a Fluidized Bed," *Transactions of the Institute of Chemical Engineers,* 74A, 133, 1996). Discussions with the NRC staff and staff members at the Brookhaven National Laboratory indicate that the boric acid/boric oxide mixture can vitrify if concentrated sufficiently and held at a high enough temperature.

3.2.1.2 Industry Accepted Boric Acid Corrosion Rates

In GL 88-05 corrosion rates were identified for pressure boundary materials of up to 0.019 inches per year (in/yr) at 500°F. For lower temperatures, corrosion rates up to 4.8 in/yr were identified. However, these corrosion rates were established for configurations which were not representative of the CRDM nozzle to head annulus gap configuration.

A Babcock & Wilcox (B&W) owners group report, BAW-10190P, "Safety Evaluation For B&W Design Reactor Vessel Head Control Rod Drive Mechanism Nozzle Cracking," was completed in May of 1993. In this report, a Combustion Engineering pressurizer heater sleeve mockup was used as the basis for establishing a 1.07 cubic inches per year corrosion rate as the applicable rate for the vessel head due to cracks in CRDM nozzles. The test results used by B&W were documented in EPRI report TR-102748S, "Boric Acid Corrosion Guidebook." This B&W analysis concluded that with this corrosion rate, a plant would remain within ASME Code structural requirements for a minimum of 6 years. The AIT identified a test note in the EPRI report which stated that the maximum volume loss of 1.07 cubic inches per year may not be conservative for all cases since the volume loss is likely to increase as the corrosion depth and wetted surface area increase.

In November of 2001, an EPRI test was documented in Revision 1 to the Boric Acid Corrosion Guidebook. This test was performed utilizing a configuration, temperature, materials and leak rates which more closely matched the CRDM nozzle to vessel configuration. This test identified a corrosion rate of up to 2.37 in/yr. This test also indicated that the maximum corrosion occurred at the location where the boric acid entered the annulus gap. The contour of the degradation observed at Nozzle 2 and Nozzle 3 appeared to support this test result.

3.2.2 Licensee Preliminary Identified Cause

The preliminary conclusions of the licensee's root cause team were documented in a memorandum to the Davis-Besse Site Vice President, dated March 22, 2002 (Attachment C). In this memorandum, the root cause team concluded: "The factors that caused corrosion of the reactor pressure vessel (RPV) head in the regions of nozzles #2 and #3 are the CRDM nozzle leakage associated with through-wall cracking, followed by boric acid corrosion of the RPV low-alloy steel." The root cause team concluded that the cracking initiated in Nozzle 3 in 1990 (+/- 3 years) and the crack had propagated through-wall between 1994 and 1996. The average rate of RPV head corrosion was identified as 2 inches per year along the line from Nozzle 3 to Nozzle 11.

In this memorandum, the root cause team also stated that: "The estimated corrosion rates are compatible with test results reported in Electric Power Research Institute's (EPRI) Boric Acid Corrosion Guidebook. They are also consistent with the video, photographic and supporting plant data, that show that significant corrosion was occurring by the 1998 to 1999 time-frame." In addition, the root cause team identified a number of causal factors such as boric acid accumulation on the top of the RPV head and flange leakage.

The AIT concluded that the licensee's root cause team had reviewed the applicable historical data and established an appropriate time-line that supported the root cause. Although the AIT agreed with the preliminary root cause conclusions, there were several crucial questions left unanswered. The licensee's root cause efforts were continuing at the conclusion of the NRC's inspection. After the conclusion of the AIT, the licensee provided their final root cause analysis report to the NRC, on April 18, 2002, and provided responses to the NRC's questions associated with the preliminary root cause report on April 30, 2002. These documents are currently under review.

4.0 HISTORY OF VESSEL HEAD INSPECTIONS AND MATERIAL CONDITION

4.1 Background CRDM Flange Leakage

Historically, CRDM flange leakage had been observed at several B&W designed plants. At Davis-Besse, CRDM flange leakage typically resulted in deposits of boric acid on the service structure above the reflective insulation. However, flange leakage in liquid form also ran down the nozzles through the clearance gaps in the insulation and became boric acid deposits on the vessel head. The access for removing the boric acid deposits and inspecting the vessel head for corrosion is through (18) 5-inch by 7-inch rectangular openings or "weep holes." These openings are at the bottom of the service structure where it is attached to the vessel head. This location combined with the curvature of the vessel head made it difficult to inspect and clean the top center portion of the vessel head. Visual inspections of the vessel head have typically been accomplished using small video cameras inserted through the weep holes. Refer to Slide 5 in Attachment B for a diagram of the vessel head.

The CRDM flanges and flange bolts are made of stainless steel, corrosion resistant materials. Although the split nut-rings, located on the underside of the lower flange face, are made of a low alloy steel and are susceptible to corrosion, they have been coated with a corrosion resistant product. The nut-rings have not been found with boric acid corrosion at Davis-Besse. Because of these corrosion resistant materials, leakage from CRDM flanges typically does not result in corrosion, and any boric acid deposits from flange leakage are normally white or light in color. Conversely, as documented in the Davis-Besse Boric Acid Corrosion Control Procedure, boric acid deposits with red or rust color indicate that corrosion has occurred.

The licensee systematically resolved CRDM flange leakage by replacing the flange gaskets with a new design. Starting in 6 RFO (1990), gaskets were replaced on flanges which had developed leaks during the previous operating cycle, such that by 10 RFO (1996), the last nine old-design gaskets were replaced even though these flanges were not leaking.

4.2 History of Flange Leakage and Reactor Head Inspections

Inspections of the reactor head associated with identifying boric acid deposits were recorded after the licensee established a Boric Acid Control Program in 1988 in response to NRC GL 88-05. The following inspection results were documented in the licensee's corrective action system through PCAQRs [potential conditions adverse to quality reports] or CRs [condition reports] and/or recorded on video-tapes:

- In April of 1990 (6 RFO) 22 leaking CRDM flanges were identified and repaired (PCAQR 90-0120).

- In September of 1991 (7 RFO) 15 out of 21 leaking CRDM flanges were repaired. Boric acid was observed on the reactor vessel head that ran along the curvature of the head and stopped on the vessel closure bolts (PCAQR 91-0353). The source of these deposits was identified as flange leakage. Cleaning was performed with a wire brush and vacuum. No surface irregularities were noted following cleaning; however, the extent of deposits if any that remained after cleaning was not documented.

- In March of 1993 (8 RFO) 14 leaking CRDM flanges were identified and 11 were repaired (PCAQR 93-0132). The boric acid from flange leakage was removed to the extent possible by washdown of the head (PCAQR 96-551). The AIT viewed a videotape of the head inspection conducted during this outage and prior to the head washdown. Discrete patches of brown and white boric acid deposits were observed which were more numerous near the center of the head.

- In October of 1994 (9 RFO) eight CRDM flanges were leaking. All eight were repaired including three leaking flanges from the previous outage (PCAQR 94-0912). No record of a reactor vessel head inspection could be found.

- In April of 1996 (10 RFO) the remaining nine CRDM flanges (non-leaking) not previously repaired were modified with an enhanced gasket design. The head was inspected and video-taped using a remote camera mounted to a hand-held pole inserted through the weep holes. Several patches of boric acid accumulation were identified including a brown stained deposit at Nozzle 67 (PCAQR 96-551). The licensee documented that boron deposits could be indicative of flange leakage or nozzle leakage. A vacuum was used to remove boric acid deposits, but was not fully effective at removing the deposits of boric acid near the center of the head. The corrosion on the head from remaining boric acid was evaluated and considered minimal based on B&W Document 51-1229638, which identified minimal boric acid corrosion of carbon steel head material at temperatures corresponding to the normal head operating temperature. The licensee concluded that 50 to 60 percent of the head had been examined during this inspection. The limited head examination appeared to be due to access restrictions caused by the weep hole access limitations and the curvature of the head. The AIT observed the videotaped inspection and noted that the boric acid deposits were generally white in color and appeared to be the consistency of loose powder and discrete lumps.

- In May of 1998 (11 RFO) one leaking CRDM flange was identified and not repaired (PCAQR 98-0649). The head was inspected and video-taped using a remote camera mounted to a hand-held pole inserted through the weep holes. This inspection identified areas near the center of the head covered with an uneven layer of boric acid (PCAQR 98-767). The licensee documented that the boric acid deposits were removed "as best as we can." The boric acid color was rust brown, which the licensee attributed to "old deposits" of boric acid. The previous root cause investigation and source documents from PCAQR 96-551 were referenced as the basis for leaving boric acid deposits on the head. The licensee concluded that due to the minimal operating time below 550°F, there was no impact on vessel head integrity. Based on review of this video-taped inspection, the AIT identified consolidated boric acid deposits near the center region including Nozzle 2 and 3 locations. On the head at an elevation below Nozzles 3 and 11, the AIT noted that the boric acid appeared highly adherent and rust brown in color.

- In April of 2000 (12 RFO) five leaking CRDM flanges were identified and repaired (CR 2000-0782). The head was inspected and video-taped using a remote camera mounted to a hand-held pole inserted through the weep holes. "Lava-like" brown/red deposits of boric acid over 1-inch thick were observed on much of the vessel head (CR 2000-1037). The corrective action for this condition was to repeat cleaning of the head until "most of the boric acid deposits are removed." Licensee logs recorded that crowbars were needed to remove the "solid rock hard deposits of boron on the head." In addition, pressurized heated water was used to remove the boric acid deposits. The extent of remaining boric acid deposits or evaluation of the effects on the head was not documented in the corrective action system after this cleaning. The system engineer also reported a large amount of boric acid deposits were observed above the mirror insulation due to flange leakage. The AIT viewed the video-taped examination made with a remote camera after the cleaning. This videotape showed a thick layer of "lava-like" brown/red boric acid that remained around the nozzles in the center of the head.

- In February of 2002 (13 RFO) no CRDM flange leakage was identified. The head was inspected and video-taped using a remote camera mounted to a hand-held pole inserted through the weep holes. The licensee documented that "more boron than expected was found on the top of the head" (CR 02-00685). Because the head was covered with boric acid and debris deposits, indications of nozzle crack induced leakage could not be positively identified at any nozzle location. The AIT reviewed pictures and tapes of this head inspection, which showed a thick lava-like brown/red deposit of boric acid covering the center of the head. Specifically, for 12 nozzles near the center of the head, the boric acid layer was several inches thick and precluded access for the remote camera inspection. The licensee subsequently removed the boric acid deposits from the head using hot pressurized water and identified the large head cavity at Nozzle 3.

The AIT noted the following important aspects in the above history of inspections and material condition of the RPV head:

(1) No flange leakage was found during 10 RFO (1996), and very limited flange leakage was noted during 11 RFO (1998). However, boric acid accumulation on the reactor vessel head increased from 9 RFO (1994) to 10 RFO (1996) and from 10 RFO (1996) to 11RFO (1998). Although the boric acid accumulation did not come from flange leakage, the licensee apparently did not deduce that it then must have come from pressure boundary leakage, such as nozzle cracking.

(2) Although five flanges were documented as leaking during 12 RFO (2000), according to CR-2000-0782, only four of the flanges showed positive evidence of gasket leakage. The fifth flange did not show the typical signs of flange leakage, but boric acid deposits had built up under the flange to the extent that the flange could not be fully inspected. This flange was for Nozzle 3, and the licensee concluded that the boric acid buildup was due to the flange leaking. The licensee apparently did not consider that the boric acid buildup could be due to nozzle leakage from below.

(3) Pictures of the reactor vessel, attached to CR-2000-0782, showed rust colored boric acid deposits emanating from the inspection openings on the reactor vessel head service structure. Although the licensee's boric acid corrosion control procedure specifically stated that corrosion will most likely be exhibited by rust stained boric acid, the source of these corrosion products was not addressed in the condition report.

5.0 OPPORTUNITIES FOR EARLY DETECTION OF HEAD DEGRADATION

The AIT evaluated plant indications that could have provided an early opportunity to detect the corrosion occurring in the vessel head. The AIT identified the following indicators which could have provided early detection of the head corrosion.

5.1 Boric Acid Corrosion Control Program

Leakage from the reactor coolant system (RCS) with the reactor at power will flash to steam and leave behind boric acid crystals. Averaged over the course of a fuel cycle, there is approximately 0.03 pounds of boric acid per gallon of primary coolant. Assuming a leak rate of 0.001 gallons per minute, approximately 15 pounds of boric acid crystals would be produced in the vicinity of the vessel head by a postulated crack in a CRDM nozzle over one year. This leak rate would be significantly less than the minimum detection capability of the plant leakage detection systems. Therefore, inspection of the reactor head for boric acid deposits is potentially the most sensitive method available for detecting small leaks caused by cracked nozzles. However, there are limitations to this method. First, depending on location, a leak may not be accessible with the reactor at power. Consequently, certain leaks can only be identified when the reactor is shut down, which may only occur during refueling outages every two years. Second, this method depends on removing all existing boric acid accumulation, so any new leak can be detected without being masked by previous accumulations. This is critical because very small leaks may not be identifiable if the preexisting accumulation is not removed.

As previously discussed in Section 4.2, the licensee had preformed visual inspections of the reactor vessel head in 7 RFO (1991), and 8 RFO (1993) in accordance with GL 88-05 guidance. Davis-Besse's implementing procedure for GL 88-05 was NG-EN-00324, "Boric Acid Corrosion Control." Although recurring CRDM flange leakage was documented during 9 RFO (1994), licensee personnel were unable to identify any records documenting the visual inspections of the head during that outage.

In addition, boric acid deposits have historically been left on the head from flange leakage as discussed in Section 4. A leaking flange typically results in boric acid deposits which travel down past the head insulation resulting in a deposit/buildup of boric acid on the head. In accordance with the boric acid control program, these deposits should have been removed and the head inspected and any corrosion evaluated.

During 10 RFO (April 1996), a licensee engineer initiated PCAQR 96-0551, "Boric Acid on Reactor Vessel Head," to document that the steps required by Procedure NG-EN-00324, "Boric Acid Corrosion Control," had not been followed during the previous outage and that the procedure could not be fully implemented due to limited access to the reactor vessel head. The evaluation presented in this PCAQR acknowledged the need to clean the vessel head, such that nozzle leakage could be detected in the future. Also, the initial assessment in this PCAQR stated that the failure to clean the boric acid deposits made it difficult to determine if the deposits occurred because of leaking flanges or because of a crack in the CRDM nozzle. Licensee managers approved the PCAQR's initial assessment subject to the following comment:

> "Nozzle cracking is of course a significant issue. However, at present, the probability of occurrence is relatively low. We should remove boron from the reactor pressure vessel head as best we can and so as to minimize dose. This will allow us to monitor any leakage, should a nozzle crack initiate."

The corrective action for this PCAQR became a Request for Modification 94-0025 (see Section 5.5.1 for additional discussion on the delay of this modification).

Because of access limitations (see Sections 4.1 and 4.2), the RPV head was not completely cleaned and some portions were not thoroughly inspected, as specified by the licensee's Boric Acid Corrosion Control Program. The bases for not cleaning or inspecting the CRDM nozzles near the center of the RPV head was documented in PCAQR's or provided by licensee staff during interviews with the AIT. Specifically, the following information was utilized by the licensee to justify leaving boric acid deposits on the RPV head as identified during inspections in 10 RFO, 11 RFO and 12 RFO:

1) B&W Owners Group stress analyses had predicted that peripheral nozzles were more likely to crack than nozzles near the center of the vessel head.
2) Dried boric acid was not corrosive to the vessel and moderate amounts of boric acid from CRDM flange leakage had historically been found and cleaned up in the past, with no vessel corrosion.
3) Very limited boric acid corrosion occurs in the temperature range existing at the vessel head.
4) EPRI's "Boric Acid Corrosion Guidebook" indicated that, under specific circumstances, a layer of boric acid potentially protects a surface from ongoing corrosion by keeping water away from the surface.
5) CRDM nozzle cracking was an age related phenomenon, and the Davis-Besse staff believed they should not see any cracking because it was several years younger than Oconee where significant problems had not yet occurred. This was codified by the B&W Owners Group in July 1997 through a probabilistic susceptibility ranking that was developed in response to the NRC's GL 97-01.

The identification of nozzle cracks at Oconee Units 1 & 3, prompted the NRC to issue Bulletin 2001-01, which requested licensees to provide information, including a description of their previous inspections of the reactor vessel head. The Davis-Besse responses of September 4 and October 17, 2001, described their previous inspection and noted that, since 1996, four of the nozzles in the center of the vessel head were obscured with boric acid deposits and could not be viewed. In addition, the licensee's responses described their analytical efforts to verify that gaps would exist between the CRDM nozzles and the reactor vessel head, permitting through-wall leakage from a crack in a nozzle to be observed via boric acid deposits.

The licensee's analyses concluded that, except for Nozzles 1, 2, 3, and 4 (center nozzles), gaps would exist during normal operating conditions through which leakage could occur and boric acid deposits would be evident. In their supplemental response to the NRC Bulletin, dated October 30, 2001, the licensee stated that based on the above analytical results, the Davis-Besse staff would not expect to see boric acid residue around Nozzles 1, 2, 3, or 4 if a crack were present. This was based on the manufactured interference fit between the nozzles and the vessel head. The notable aspect of this conclusion was that the analytically predicted interferences ranged from 0.000025 to 0.000004 inches. Because the fabrication tolerances were more than an order of magnitude greater than the analytical results, the AIT considered the licensee's conclusion, relative to not expecting boric acid residue if a crack were present in these nozzles, to be unrealistic.

During interviews with the AIT, licensee personnel acknowledged that the reactor vessel head was treated less rigorously than other components in the plant, within the context of the GL 88-05 program. Although the boric acid corrosion control program was appropriately entered when boric acid was identified on the reactor vessel head, the resolution of the issue was not treated the same. Using the longstanding rationale discussed above, the licensee used a philosophy that boric acid had been on the reactor head for many years and no problems had ever been found.

5.2 Reactor Coolant System Leakage Detection

Because leakage from the through-wall cracks in Nozzle 3 would result in reactor coolant leakage into the containment atmosphere, the leakage detection systems in containment were reviewed to determine whether this system could have provided an early indicator of head corrosion. The observed leakage rate from a cracked nozzle would be expected to be very small based on a leakage rate (0.003 gallons per minute (gpm)) attributed to CRDM nozzle cracks observed at a foreign reactor plant (Bugey).

Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," details requirements for leakage monitoring equipment such as the containment atmosphere particulate and gaseous radioactivity monitoring systems and containment sump level/flow monitoring system. The licensee has implemented a leak detection program in accordance with Regulatory Guide 1.45 as described in the Updated Safety Analysis Report, Section 5.2.4.

Reactor coolant system (RCS) leakage is grouped into two categories: identified and unidentified. Identified leakage is that which is captured and metered through closed systems, such as a collecting tank (e.g., pump seals and valve packing leaks); leakage into containment atmosphere from sources that are both specifically located and known not to interfere with the operation of leakage detection systems or not to be pressure boundary leakage; leakage through the steam generators to the secondary system; and reactor coolant pump seal returns. Unidentified leakage is everything which is not identified leakage.

Unidentified RCS leakage was normally less than 0.1 gpm (monthly average), until October of 1998, when a decision was made to remove the rupture disks downstream of the pressurizer relief valves for design concerns (PCAQR 98-1980). Specifically, a drain line, designed to collect relief valve leakage in the quench tank, was bypassed in this modification. This allowed leakage past the relief valves to be vented directly into the containment atmosphere, which collected in the normal sump and added to the unidentified leakage, which increased to a maximum of 0.8 gpm. During a mid-cycle outage in May of 1999, the licensee resolved this design concern by installing new rupture disks and reconnecting the drain line. This resulted in a decrease in unidentified leakage. However, the unidentified leakage returned to levels between 0.15 and 0.25 gpm. Subsequent investigations and containment entries were not successful in identifying definitive sources of this leakage. The licensee concluded, based upon the history of CRDM flange leakage and that unidentified leakage values observed at Davis-Besse were near industry averages, the leakage was most likely from the CRDM flanges.

Because of historical variations in unidentified leakage compared to the relatively small amount of leakage associated with CRDM cracks, the AIT concluded that, by itself, unidentified leakage trends were not a reasonable method of detecting nozzle cracking. However, when considered together with other indications of corrosion products as discussed in Section 4.2, above, and in Sections 5.3 and 5.4 below, the AIT concluded that this was a missed opportunity to detect the corrosion occurring on the reactor vessel head.

5.3 Containment Air Coolers

Reactor coolant leakage through the cracks in Nozzle 3 would travel as steam and liquid in the annulus behind the nozzle and leave boric acid deposits on the top of the head. In addition, this steam leakage would cause boric acid and corrosion products from the head cavity to be divided into fine particles which would be dispersed into the air space above the head. These fine particles would then be captured by the service structure ventilation system intake and be distributed throughout the containment. A key area which could collect these airborne particles of boric acid and corrosion products is at the containment air coolers (CAC).

The vessel head service structure ventilation pulls a suction from the CRDM flange area through the fans located on the 603 feet elevation, exhausting through ductwork to the top of the East D-ring. This provided a potential pathway for any corrosion fines and boric acid particulate dispersion originating from the vessel head. In November of 2001, radiological surveys showed a contamination plume effect originating from the service structure ventilation exhaust over the East D-ring. However, an isotopic analysis was not performed of the plume to fully characterize the source of the contamination. Additionally, two containment recirculation fans provide a mixing of the containment atmosphere, further dispersing the fines and particulates.

The CAC system consists of three separate tube/fin coolers (which are cooled by the service water (SW) system) located inside containment, and connected to a common supply plenum. Downstream of this plenum is a ductwork distribution system, designed to distribute air over and around all heat producing equipment, such as the reactor vessel, D-rings (housing the steam generators, pressurizer and reactor coolant pumps) and incore instrument tank. The external surfaces of the cooler tube banks are readily visible from the outside of the coolers, and have a remote indication of plenum pressure (used to determine cooling fin fouling) in the control room.

If a leak occurs from the RCS during normal operations, an aerosol mist is produced from the water flashing and evaporating as it exits the leak, increasing containment ambient humidity. Since the inlet water temperature of SW to the CACs is normally between 40°F and 75°F, substantially cooler than containment air temperatures, the CACs condense this ambient humidity to water, which is ultimately collected in the normal containment sump. In the process of removing the humidity, the CACs also collect particulate boric acid (which would be released with the RCS leakage as fine particles) on the cooling fins, in the discharge plenum and the associated ductwork. This fouling will decrease the plenum pressure, as read remotely in the control room, during periods of high boric acid accumulation.

In 1992, the licensee had experienced a CAC fouling from a leak in the reactor head vent line flange to the primary side of the steam generator. As a result, the licensee cleaned the boric acid, evident by the uniformly white coating on all three coolers. After repairs to the flange, no further boric-acid precipitated cleanings were required for several years.

In October of 1998, the removal of the rupture disks downstream of the pressurizer relief valves substantially contributed to the RCS unidentified leakage. In November 1998, PCAQR 98-1980 identified that the CAC fouling had increased correspondingly to increased leakage from the pressurizer reliefs. The CACs were cleaned 17 times from November 1998 to May 1999. During a mid-cycle outage in May 1999, the design concern was resolved, the rupture disks reinstalled, and the drain line reconnected. However, two additional CAC cleanings were conducted, one in June 1999 and one in July 1999. The post-job critique observed the boric acid to be "rust color on and in the boron being cleaned away" from CAC No. 1. Subsequent interviews indicated this was presumed to be the result of restoring from the mid-cycle outage, and the residual humidity in containment from outage-related repairs. After being cleaned in July 1999, the CACs did not need any further cleaning for approximately 10 months. Although the licensee installed high efficiency particulate air filters (inside containment) during August and September 1999, this did not appear to factor into the need for CAC cleaning.

After 12 RFO (May of 2000), CAC deposits were again forming, as evidenced by the decrease in plenum pressure. Eight CAC cleanings were conducted between June 2000 and May 2001, with no further cleanings required through the end of cycle. However, for 13 RFO (February 2002), the licensee reported (15) 5-gallon buckets of boric acid were removed from the ductwork and plenum. Significant boric acid was found elsewhere within containment, including on SW piping, stairwells and other areas of low ventilation.

After the 1999 mid-cycle outage, the licensee had attributed the excessive boric acid accumulation and CAC cleanings to leakage from CRDM flanges. In 12 RFO (May 2000), several leaking flanges were repaired, the results of which could not be verified throughout the cycle. However, 13 RFO (February 2002) inspections indicated the repairs had been successful, and no flange leakage was detected. Furthermore, earlier experience with leaking flanges (pre-1992, and 1992-1998) did not result in the need to clean the CACs. Therefore, CRDM flange leakage would not have reasonably been the major contributor to the increased boric acid loading on the CACs during this time frame. The licensee had also attributed the discoloration of the boric acid to migration of the surface corrosion on the CACs into the boric acid and the aging of the boric acid itself.

The AIT considered the sudden change to rust colored boric acid deposits in June of 1999, to indicate corrosion product accumulation from the formation of the head cavity near Nozzle 3. The failure of the licensee to identify the source of these deposits represented a missed opportunity to identify the corrosion cavity in the head at that time.

5.4 Radiation Elements

As discussed in Section 5.2, steam leakage through the cracks in Nozzle 3 would result in fine particles of boric acid and corrosion products. These particles would then be captured by the service structure ventilation system intake and distributed throughout the containment. An area where these fine particles of boric acid and corrosion products would be collected and observed is in the radiation element (RE) system filters.

There are two identical radiation element air sampling systems, drawing from two sample locations within containment. Air samples are drawn from within containment, passed through a particulate filter, an iodine sample cartridge and a noble gas detector before being exhausted back into containment. Both systems normally draw a sample from near the top of the "D-ring" structures, but can also draw from near the polar crane, and near the personnel airlock on the 603 feet elevation.

Boric acid accumulation on the RE filters can clog the filters and decrease flow to below acceptable levels, necessitating a filter change. Licensee records correlate past RCS leakage increases with RE filter changes, such as in 1992 when the reactor head vent flange leakage caused this to occur. In March of 1999, RE filter clogging from boric acid deposits was attributed to the pressurizer relief valve rupture disk maintenance which occurred in 1998. Filter changes normally occurred based on a monthly schedule rather than low flow rates. Beginning in May of 1999, the schedule of filter change out went from a monthly interval to an irregular 1 to 3 week interval, occasionally dropping to a 1 to 2 day interval by November 1999. In response to the increased frequency of filter changeouts, the licensee installed two large high efficiency particulate air filter units inside containment to capture a large portion of the corrosion fines. Additionally, the RE sample points were changed to the alternate locations. This action appeared to improve the service life of the filters, but did not eliminate the filter loading conditions completely.

In May of 1999, the RE filters began accumulating a yellowish-brown material. This material was sent to an external laboratory for analysis. The results of this analysis were received in November 1999, and positively identified the presence of ferric oxide. Specifically, this analysis stated, "The fineness of the iron oxide (assumed to be ferric oxide) particulate would indicate it probably was formed from a very small steam leak. The particulate was likely originally ferrous hydroxide in small condensed droplets of steam and was oxidized to ferric oxide in the air before it settled on the filters;" and "the iron oxide does not appear to be coming from the general corrosion of a bare metal surface in containment or from steam impingement on a metal surface."

Accumulation of boric acid on the RE filters was readily recognized as a symptom of RCS leakage. During 12 RFO, CRDM flange D10 was attributed as the source of the RCS leakage, since the flange required machining to correct the leakage. However, the presence of ferric oxide fines was not explained, nor were multiple containment entries successful in determining a source. Additionally, past CRDM flange leakage had not significantly contributed to the CAC fouling, nor the RCS leakage indications. Therefore, the AIT believed that the corrosion deposits first identified in the RE filters beginning in May of 1999, indicated that corrosion was occurring due to the formation of the head cavity near Nozzle 3. The failure of the licensee to identify the source of these corrosion products represented a missed opportunity to identify the corrosion cavity in the head at that time.

5.5 Causal Factors Influencing Head Degradation Detection

Several decisions made by Davis-Besse personnel at various times directly influenced or potentially affected their ability to detect the head degradation associated with the CRDM nozzle leakage. These are discussed below.

5.5.1 Decision to Delay Modification to Service Structure

In March of 1990, modification 90-0012 was initiated to install multiple access ports in the service structure to permit inspection and cleaning of the vessel head. This modification was canceled in 1992, because the current inspection techniques were considered adequate.

In March of 1994, a licensee engineer initiated PCAQR 94-0295 to question why there was no commitment requiring a visual inspection of the reactor vessel head every refueling outage, as referenced in the NRC 1993 Safety Evaluation for the Alloy 600 CRDM nozzle cracking issue. The PCAQR's response from the Nuclear Assurance Director indicated that the commitment for the visual inspection did not appear to have been a licensee commitment to the NRC. Regulatory Affairs and Design Engineering personnel indicated that, although an enhanced visual was not a commitment to the NRC, they recommended the visual inspection be done. However, the plant engineering staff's comment in the PCAQR stated that there was a low risk of a crack in CRDM nozzles since none had been identified in the United States, and that the available inspection methods were not highly reliable. On that basis, the plant engineer felt it was not necessary to perform the inspections.

In May of 1994, the licensee engineer who wrote the above PCAQR initiated a Request for Modification (RFM 94-0025) to install openings in the CRDM service structure to allow thorough inspection and cleaning of the reactor vessel head. The modification request noted that, out of all of the B&W plants, only Davis-Besse and Arkansas Nuclear One, Unit 1, had not installed the access openings in the service structure. The modification request cited the following reasons for the modification:

1) there was no access to the reactor vessel head or CRDM nozzles without the modification, and there was an ongoing industry concern for Alloy 600 nozzle cracking;

2) inspection of the reactor vessel head for boric acid corrosion was difficult and not always adequate, because the video inspections did not encompass a 100 percent inspection of the head;
3) cleaning boric acid residue from the vessel head did not encompass 100 percent, because the size and geometry of the weep holes only permitted cleaning of the lower one-third of the head with scrapers and wire brushes.

The modification was approved by the plant in July of 1994, but remained unfunded by the Project Review Committee/Project Review Group until November of 1998, when it was scheduled for implementation in 13 RFO (2002). The modification was subsequently deferred until 14 RFO by the Project Review Group, as part of an effort to meet the 2001/2002 expenditure targets by reducing the number of projects implemented. In discussing the reasons for not implementing this modification, the rationale identified in Section 5.1 were also applied. The AIT considered the delay in implementing the modification as contributing to the failure to detect head degradation.

5.5.2 Decision to Delay Repair of CRDM Flange on Nozzle 31 in 11RFO

During 8 RFO (1993), CRDM flange leakage was noted on several CRDM flanges including the flange for Nozzle 31. The corrective actions included polishing the flange surface and replacing the gasket with a new design. The PCAQR issued to document this condition (93-0132) contained a recommendation that the flange surface be inspected during each subsequent maintenance outage and be machined if further leakage occurs. During 11 RFO (1998), the CRDM flange for Nozzle 31 was found to be leaking, and as indicated in PCAQR 98-0649, the amount of leakage was not considered significant compared to flange leakage from previous outages. Consequently, no corrective actions were taken, even though the vendor (Framatome) reiterated their recommendation from 1993 to machine the flange. The PCAQR did contain a recommendation to reexamine the flange for Nozzle 31 during 12 RFO and to replace the gasket if the flange was leaking.

During 12 RFO (2000), significant flange leakage was noted and five leaking flanges were identified during the video inspections of the CRDM flanges, including Nozzle 31's. The majority of the boric acid accumulation was attributed to Nozzle 31's flange due to steam cutting of the flange face. Condition Report 2000-1037 was written to describe the boric acid accumulation on the RPV head and on top of the insulation. The boric acid accumulation was attributed to leaking CRD flanges. The AIT considered the delay in repairing Nozzle 31's flange as a contributing cause of this event, because the extensive amount of flange leakage contributed to the boric acid deposits on the head which masked evidence of the nozzle leakage occurring at this time.

6.0 CONCLUSIONS

The AIT presented the inspection results to Mr. Saunders and other members of the licensee management at the conclusion of the inspection on April 5, 2002. The licensee acknowledged the conclusions presented as discussed in Attachment B and summarized below.

The AIT concluded that the probable cause of the cavity at Nozzle 3 was boric acid corrosion of the head associated with reactor coolant leakage from a through-wall crack in this nozzle. Further, the AIT concluded based on corrosion products observed on the head, and in the CAC and RE filters that the corrosion process had been in progress for at least 4 years.

The AIT concluded that the probable cause of the cracking observed in the five penetration nozzles was PWSCC. This was based on similar cracking identified at two other B&W plants that performed destructive analysis of cracked nozzles fabricated from the same heat of material to confirm PWSCC.

The AIT evaluated the indications which existed that could have provided an early opportunity to detect evidence of the formation of the corrosion cavity in the head at Nozzle 3. The AIT identified several opportunities which were available to the licensee to potentially identify this corrosion cavity at an earlier point in time. Specifically, these missed opportunities were associated with the failure to identify the source of the corrosion products deposited in the CAC and RE filters in early 1999 and the failure to remove boric acid or evaluate the source of corrosion products which accumulated on the vessel head.

KEY POINTS OF CONTACT

DAVIS-BESSE

H. Bergendahl, Vice President - Nuclear
D. Eshelman, Director, Support Services
R. Fast, Plant Manager
D. Geisen, Manager, Design Engineering
D. Lockwood, Manager, Regulatory Affairs
J. Messina, Director, Work Management
D. Miller, Supervisor, Compliance
S. Moffit, Director, Technical Services
R. Saunders, President, FirstEnergy Nuclear Operating Company

NUCLEAR REGULATORY COMMISSION

J. Davis, Sr. Material Engineer, NRR
R. Gardner, Chief, Engineering Branch
J. Grobe, Director, Division of Reactor Safety
C. Lipa, Chief, Reactor Projects Branch 4
B. Sheron, Associate Director for Project Licensing and Technical Analysis, NRR

LIST OF ACRONYMS USED

AIT	Augmented Inspection Team
ASME	American Society of Mechanical Engineers
B&W	Babcock and Wilcox
CAC	Containment Air Cooler
CR	Condition Report
CRDM	Control Rod Drive Mechanism
EPRI	Electric Power Research Institute
GL	Generic Letter
gpm	Gallon Per Minute
in/yr	Inches Per Year
NRC	Nuclear Regulatory Commission
PCAQR	Potential Conditions Adverse to Quality Report
PDR	Public Document Room
PWSCC	Primary Water Stress Corrosion Cracking
RCS	Reactor Coolant System
RE	Radiation Element
RFO	Refueling Outage
RPV	Reactor Pressure Vessel
SW	Service Water

LIST OF DOCUMENTS REVIEWED

Calculation

SIA Calc W-ENTP-11Q-306	Finite Element Gap Analysis of CRDM Penetrations (Davis-Besse), October 8, 2001.

Condition Reports (CR)

1992-0139	Boron Found on Containment Air Sample Filter
1993-0187	Boric Acid Accumulation on SW Piping
1998-0020	Multiple Problems Identified with RC-2
1998-0330	Industry Event (Prairie Island) Crack in the Motor Tube of the Control Rod Drives
1998-1963	Design Over-Stress of the Pressurizer Nozzles for Safety Valve
1999-0372	Received Computer PT-RE4597AA/AB High
1999-0510	Low Flow Alarm Observed on RE4597BA While Out of Service for Maintenance
1999-0745	Small Clumps of Boric Acid Present on Wall Opposite of DH108
1999-0861	RE4597AA Sample Lines Were Found to be Full of Water
1999-0928	Increased Frequency of Particulate and Charcoal Filters for RE 4597BA Being Changed
1999-0998	Awareness of Approaching the Tech Spec Limit for Maximum Ctmt Air Temp
1999-1300	Analysis of CTMT Radiation Monitor Filters
1999-1614	Due Date of LER Commitment Missed: Boric Acid Control Program Procedure Change
2000-0781	Leakage from CRD Structure Blocked Visual Exam of Reactor Vessel Head Studs
2000-0782	Inspection of Reactor Flange Indicated Boric Acid Leakage From Weep Holes
2000-0903	Two of 40 CRDM Hold Down Bolts Had Indications Found During VT-1 Inspection
2000-0994	RV Head CRDM Nozzle at Location F-10 has Large Pit in Outer Gasket Groove
2000-0995	RV Head CRDM Nozzle Flange at Location D-10 has Extensive Pitting Across the Outer Gasket Groove. Inner Gasket Also Has Pitting
2000-1037	Inspection of Reactor Head Indicated Accumulation of Boron in Area of the CRD Nozzle Penetration
2000-1210	During Installation of Control Rod Drive Assembly at Location D-10, on the Reactor Head, it was Discovered that Top of Motor Tube for this Drive was out of Line with Surrounding Motor Tubes
2000-1547	CAC Plennum Pressure Drop Following 12 RFO
2000-4138	Frequency for Cleaning Boron From CAC Fins Increased to Interval of Approximately 8 weeks
2001-0039	CAC Plenum Pressure Experienced Step Drop
2001-0487	Certain Areas Inside CTMT in Year 2000 Seeing Higher Temperatures
2001-0890	Unidentified RCS Leak Rate Varies Daily by as Much as 100 percent of the Value
2001-1110	Chemistry is Changing Filters on RE4597BA More Frequently
2001-1822	Frequency of Filter Changes for RE4597BA is Increasing
2001-1857	RCS Unidentified Leakage at .125 to .145 gpm
2001-2012	NRC Issuance of IEB 01-01 Circumferential Cracking of RX Pressure Vessel Head Penetration Nozzles

2001-2769	RE2387 Identified Spiked Above ALERT and High Setpoints
2001-2795	RE4597BA Alarmed on Saturation
2001-2862	Calculated Unidentified Leakage for Reactor Coolant System has Indicated Increasing Trend
2001-2936	Monthly Functional Test for RE4597BA/BB Count Not Performed
2001-3025	Increase in RCS Unidentified Leakage
2001-3411	Received Equipment Fail Alarm for Detector Saturation on RE4597BA
2002-0685	Loose Boron 1-2" deep 75% Around Circumference of Flange
2002-0846	More Boron Than Expected Found on Top of Head
2002-0891	UT Performed on #3 CRDM Nozzle Revealed Indication of Through-Wall Axial Flaws
2002-0932	Completion of UT on All 69 CRDM Nozzles Revealed Additional CRDM Cracks Beyond #3 Nozzle
2002-1053	While Machining Reactor Vessel Head Nozzle #3 the Nozzle Machining Tool Moved Approximately 15 Degrees
2002-1128	Evaluation of Bottom up Ultrasonic Test Data in Area of RX Pressure Vessel Head Nozzle #3 Shows Significant Degradation of RX Vessel Head Pressure Boundary
2002-1159	During Video Tape Review, Indication Found on Newly Machined Face on Mid-Span of CRDM Nozzle. Appears to be Through-wall in Immediate Vicinity of Base Metal Indications.

Drawings

M-503-127-3	Closure Head Assembly, Revision 3
M-503-212-1	Closure Head Subassembly Drawing, Revision 1
M-503-213-2	Closure Head Subassembly Drawing, Revision 2
03-1221681-03	Framatome Drawing of RV Nozzle/Nur Ring Modification

Modifications

MOD 90-0012	Modification Reactor Closure Head Access Ports
MOD 94-0025	Install Service Structure Inspection Openings
TM 1998-0036	Temporary Modification: Preliminary Evaluation of Pressurizer Nozzles for Relief Valves Demonstrates that an Overstress Condition May Exist in the Nozzle Flange

NRC Generic Communications for Control of Boric Acid Corrosion

IN 80-27	Degradation of Reactor Coolant Pump Studs, dated June 11, 1980
IEB 82-02	Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants, dated June 2, 1982
IN 82-06	Failure of Steam Generator Primary Side Manway Closure Studs, dated March 12, 1982
IN 86-108	Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion, dated December 29, 1986
IN 86-108	Supplement 1, dated April 20,1987
IN 86-108	Supplement 2, dated November 19, 1987
IN 86-108	Supplement 3, dated January 5, 1995

GL 88-05	Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants, dated March,17, 1988
IN 90-10	Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600, dated February 23,1990
IN 94-63	Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks, dated August 30, 1994
IN 96-11	Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations, dated February 14,1996
GL 97-01	Degradation of CRDM/CEDM Nozzle and other Vessel Closure Head Penetrations, dated April 1, 1997
IN 2001-05	Through-wall Circumferential Cracks of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3, dated April 30, 2001
Bulletin 2001-01	Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles, dated August 3, 2001

<u>Other Documents</u>

RAS02-00132	Probable Cause Summary Report for CR2002-0891, dated March 22, 2002
NPE-96-00260	Control Rod Drive Nozzle Cracking, dated May 8, 1996
Books	RCS System Performance Books Volumes 1 though 11
BAW-10190P	Safety Evaluation For B&W Design Reactor Vessel Head Control Rod Drive Mechanism Nozzle Cracking, dated May of 1993
BAW-10190P, Addendum 1	B&W Owners Group Proprietary, External Circumferential Crack Growth Analysis for B&W-Design Reactor Vessel Head Control Rod Drive Mechanism Nozzle Cracking, dated December 1993
BAW-2301	B&W Owners Group Proprietary, B&WOG Integrated Response to Generic Letter 97-01, dated July 1997
Exam Report	Reactor Vessel Head ID Clad Thickness Measurements in Region of Wastage Between Nozzles 3 and 11, dated March 18, 2002
Exam Report DB-5	CRDM Nozzle 46 J-Groove Weld, dated March 24, 2002
Examination Report	Davis Besse 13 RFO CRDM Nozzle Examination Report, dated March 11, 2002
Framatome 51-5015818-00	Davis-Besse CRDM Nozzle Heat Information, 2002
EPRI Report TR-102748s	Boric Acid Corrosion Guidebook, Revision 0, dated April 1995
EPRI Report 1000975	Boric Acid Corrosion Guidebook, Revision 1, dated November 2001
Report 2779	Oconee Unit 3 CRDM Nozzle Crack and Material Characterization - Oconee Unit 1 Thermocouple Tube material Characterization - Metallurgical Analysis Report
Dominion Engineering Report	Volume and Weight of Material Lost at Nozzle 3
51-125825-00	CRDM Nozzle Heat Treatment

Material Test Report	DBNPS Reactor Vessel Head Certified Material Test Report
Intra-Company Memorandum	Control Rod Drive Nozzle Cracking, dated May 8, 1996
Root Cause Plan	Dated March 18, 2002.
Intra-Company Memorandum	Probable Cause Summary Report for CR2002-0891, dated March 22, 2002
Meeting Minutes	DBPRC Meeting Minutes for MOD 94-0025.
Standing Order 87-015	RCS Leakage Management and Attached Policy Reactor Coolant System Leakage Management
0620-00143210	Lukens Steel Company, Test Certificate, Chemical Analysis and Physical Properties

Photographic Records

Picture	Vessel Head on Stand
Picture	Head and Service Structure Looking NE
Picture	Scaffolding Around Service Structure
Picture	View From Newly Cut Service Structure Manway Opening Looking into Drives
Picture	Looking Through Manway Cut in Service Structure
Picture	View of CRD Flanges Above Insulation Showing Some Removed and Some Installed
Picture	Control Rod Drive Flanges Above Insulation
Pictures	Shielded Work Platform on Top of Service Structure
Picture	Pictures of Nozzle 2 and 3
Pictures	Area Surrounding Nozzle 3 Penetration
Picture	Nozzle 16 Quad C
Pictures	Nozzle 2
Pictures	Nozzle 3 Remnant
Pictures	From Bare Head Video Exam Conducted in 13 RFO.
Video Tape	Davis-Besse Reactor Head Inspection Under Insulation Alloy 600, 12 RFO
Video Tape	Davis-Besse 12 RFO Final Head Inspection
Video Tape	Davis-Besse Reactor Head Cleaning 11 RFO
Video Tape	Davis-Besse Weep Hole Cleaning Nozzle 67, 10 RFO
Video Tape	Davis-Besse Weep Hole Video Inspection 10 RFO
Video Tape	13 RFO Reactor Head Nozzle Remote Visual Inspection
Video Tape	Root Cause Video of Nozzle #3 and Adjacent Nozzles, March 13, 2002 to March 14, 2002
Video Tape	PT of Nozzle #46 J-groove Weld, March 24, 2002

Potential Conditions Adverse to Quality Reports (PCAQR)

1988-0494	Condition Not Satisfactorily Resolved per PCAQ
1990-0221	CRDM Flanges #F02 and F-4 Erosion and Irregularities.
1991-0353	Boron on Reactor Vessel Head
1992-0072	CAC Cleaning
1993-0098	Boric Acid Corrosion on OTSGA Head Vent Flange
1993-0132	Reactor Coolant Leakage from CRD Flange

1994-0912	Documents Results of CRDM leakage Video Inspection
1994-0974	CRDM Flange Indication
1994-0975	CRDM Flange Indication
1994-1338	10 CFR Part 21 RX Adaptor Tubes
1996-0551	Boric Acid on RX Vessel Head
1996-0650	VT-2 Inspection Revealed Evidence of Leakage and Boric Acid Residue
1996-1018	IN 96-032 RV Augmented ISI
1998-0020	Inadequate Testing
1998-0649	Reactor Vessel Head Boron Deposits
1998-0767	Reactor Vessel Head Inspection Results
1998-0824	CAC Boric Acid Accumulation
1998-1164	Water in RE4597 Sample Lines
1998-1885	Found Two Carbon Steel Nuts on RC2
1998-1895	CTMT Normal Sump Leakage in Excess of 1 gpm
1998-1965	Water and Boron Accumulation on Filter Cartridges
1998-1980	Potential CAC Fouling
1998-2071	Accumulation of Boric Acid on CTMT Service Water Piping

Procedures

NG-EN-00324	Boric Acid Corrosion Control, Revisions 1, 2, and 3
PP-1102.10	Surveillance Test Procedure: Plant Shutdown and Cooldown, Revision 16
DB-OP-06903	Operations Procedure: Plant Shutdown and Cooldown
DB-PF-00204	ASME Section XI Pressure Testing, Revision 3
DB-OP-01200	Reactor Coolant System Leakage Management, Revision 3

ATTACHMENT A TO NRC AUGMENTED INSPECTION REPORT NO. 50-346/02-03(DRS)

USNRC Memorandum from J. E. Dyer to R. N. Gardner, dated March 12, 2002: Augmented Inspection Team Charter - Davis-Besse Reactor Vessel Head Material Loss

Documented in ADAMS (Accession Number ML020730194)

ATTACHMENT B TO NRC AUGMENTED INSPECTION REPORT NO. 50-346/02-03(DRS)

NRC Briefing Slides for the Public AIT Exit Meeting Conducted on April 5, 2002

Documented in ADAMS (Accession Number ML021070811).

ATTACHMENT C TO NRC AUGMENTED INSPECTION REPORT NO. 50-346/02-03(DRS)

FirstEnergy Intra-Company Memorandum from S. A. Loehlein to H. W. Bergendahl, dated March 22, 2002

Documented in ADAMS (Accession Number ML020860035)

March 12, 2002

MEMORANDUM TO: Ronald N. Gardner, Chief
Electrical Engineering Branch
Division of Reactor Safety

FROM: J. E. Dyer ***/RA/***
Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER - DAVIS BESSE REACTOR VESSEL HEAD MATERIAL LOSS

In response to preliminary information provided by the licensee on March 10, 2002, regarding the significant loss of pressure boundary material from the reactor vessel head, an augmented inspection team (AIT) is being sent to the Davis-Besse Plant. You are hereby designated as the AIT leader.

A. Basis

On March 6, 2002, during repair activities to control rod drive mechanism (CRDM) nozzles, the licensee identified an area of wastage in the reactor pressure vessel head surrounding the No. 3 CRDM nozzle. The licensee initially identified five CRDM nozzles that required repairs due to cracking in the J-groove welds found during the nozzle examinations required by Bulletin 2001-01. Wastage area in the head was discovered when the licensee removed the No. 3 CRDM nozzle, after the penetration tube unexpectedly moved during repair activities.

Because this was a significant unplanned degraded condition having potential generic safety implications, an AIT was initiated in accordance with NRC Management Directive 8.3, "NRC Incident Investigation Program." The purpose of the AIT is to better understand the facts and circumstances related to the degradation of the reactor vessel head pressure boundary material. It is also to identify any precursor indications of this condition so that appropriate followup actions can be taken. All followup actions associated with the extent of condition, repairs/replacements, or corrective actions related to plant restart will be covered through other inspection activities.

CONTACT: John A. Grobe, Director, DRS
(630) 829-9700

B. Scope

Specifically, the augmented inspection team is expected to collect, analyze, and document factual information and evidence sufficiently to address the following:

1. The plant history of reactor coolant system operational leakage indications, including trends in unidentified leakage, containment air cooler fouling, containment radiation monitor readings, etc.

2. The plant history of reactor vessel head material condition issues, including control rod drive flange leakage or other sources of corrosive substances.

3. The plant history of reactor vessel head inspection, including visual inspections, ultrasonic testing, prior video-records of head examinations, reactor vessel head cleaning activities, and licensee action in response to generic correspondence for leakage and degradation of the reactor coolant system.

4. Characterization of all reactor vessel head wastage areas, including the best available geometric details of cavity volumes, surface conditions, surface contaminants, etc.

5. The probable cause(s) for the vessel head wastage.

C. Guidance

This memorandum designates you as the AIT leader. Your duties will be as described in Inspection Procedure 93800, "Augmented Inspection Team." The team composition has been discussed with you directly. During performance of the augmented inspection, designated team members are separated from their normal duties and report directly to you. The team is to emphasize fact-finding in its review of the circumstances surrounding the event, and it is not the responsibility of the team to examine the regulatory process, to determine whether NRC requirements were violated, to address licensee actions related to plant restart, or to address the applicability of generic safety concerns to other facilities. Safety concerns identified that are not directly related to the event should be reported to the Region III office for appropriate action.

The team will report to the site, conduct an entrance meeting, and begin inspection on Tuesday, March 12, 2002. Tentatively, the inspection should be completed by close of business March 22, 2002, with a report documenting the results of the inspection, including findings and conclusions, issued within 30 days of the public exit meeting. While the team is on site, you will provide daily status briefings to Region III management.

This Charter may be modified should the team develop significant new information that warrants review.

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OFFICE	RIII	RIII	RIII	RIII
NAME	JGavula:sd	CLipa	JGrobe	JDyer
DATE	3/12/02	3/12/02	3/12/02	3/12/02

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Reference E

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

MAR. 17, 1988

ALL LICENSEES OF OPERATING PWRS AND HOLDERS OF CONSTRUCTION PERMITS FOR PWRS

GENTLEMEN:

Subject: BORIC ACID CORROSION OF CARBON STEEL REACTOR PRESSURE BOUNDARY COMPONENTS IN PWR PLANTS (GENERIC LETTER 88-05)

Pursuant to 10 CFR 50.54(f), the Nuclear Regulatory Commission is requesting information to assess safe operation of pressurized water reactors (PWRs) when reactor coolant leaks below technical specification limits develop and the coolant containing dissolved boric acid comes in contact with and degrades low alloy carbon steel components. The principal concern is whether the affected plants continue to meet the requirements of General Design Criteria 14, 30, and 31 of Appendix A to Title 10 of the Code of Federal Regulations (CFR) Part 50 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. Our concerns regarding this issue were prompted by incidents in PWR plants where leaking reactor coolant caused significant corrosion problems. In many of these cases, although the licensees had detected the existence of leaks, they had not evaluated their significance relative to the safety of the plant nor had they promptly taken appropriate corrective actions. Recently reported incidents are listed below.

(1) At Turkey Point Unit 4, leakage of reactor coolant from the lower instrument tube seal on one of the incore instrument tubes resulted in corrosion of various components on the reactor vessel head including three reactor vessel bolts. The maximum depth of corrosion was 0.25 inches. (IE Information Notice No. 86-108, Supplement 1)

(2) At Salem Unit 2, leakage occurred from the seal weld on one of the instrument penetrations in the reactor vessel head, and the leaking coolant corroded the head surface. The maximum depth of corrosion was 0.36 inches. (IE Information Notice No. 86-108, Supplement 2)

(3) At San Onofre Unit 2, boric acid solution corroded nearly through the bolts holding the valve packing follow plate in the shutdown cooling system isolation valve. During an attempt to operate the valve, the bolts failed and the valve packing follow plate became dislodged causing leakage of approximately 18,000 gallons of reactor coolant into the containment. (IE Information Notice No. 86-108, Supplement 2)

(4) At Arkansas Nuclear One Unit 1, leakage from a high pressure injection valve dripped onto the high pressure injection nozzle. The maximum depth of corrosion was 0.5 inches, which represented a 67 percent penetration of the pressure boundary. (IE Information Notice No. 86-108)

(5) At Fort Calhoun, seven reactor coolant pump studs were reduced by boric acid corrosion from a nominal 3.5 inches to between 1.0 and 1.5 inches. (IE Information Notice 80-27)

Additionally, corrosion rates of up to 400 mils/month have been reported from an experimental program. (IE Information Notice No. 86-108, Supplement 2)

Although failure of the reactor coolant pressure boundary did not occur in every instance, all of these incidents demonstrated the potential adverse consequences of boric acid corrosion.

The corrosion caused by the leaking coolant containing dissolved boric acid has been recognized for some time. Since 1979, the NRC has issued five information notices (80-27; 82-06; 86-108; and 86-108, Supplements 1 and 2) and Bulletin 82-02 addressing this problem. In June 1981, the Institute for Nuclear Power Operations issued a report discussing the effect of low level leakage from the gasket of a reactor coolant pump and concluded that significant corrosion of the pump studs could occur during all modes of operation. In December 1984, the Electric Power Research Institute issued a summary report on the corrosion of low alloy steel fasteners which, among other things, discussed boric acid-induced corrosion. The information contained in these documents clearly indicated that boric acid solution leaking from the reactor coolant system can cause significant corrosion damage to carbon steel reactor coolant pressure boundaries.

Office of Inspection and Enforcement (IE) Bulletin 82-02 requested licensees to identify all of the bolted closures in the reactor coolant pressure boundary that had experienced leakages and to inform the NRC about the inspections to be made and the corrective actions to be taken to eliminate that problem. However, the bulletin did not require the licensees to institute a systematic program for monitoring small primary coolant leakages and to perform maintenance before the leakages could cause significant corrosion damage.

In light of the above experience, the NRC believes that boric acid leakage potentially affecting the integrity of the reactor coolant pressure boundary should be procedurally controlled to ensure continued compliance with the licensing basis. We therefore request that you provide assurances that a program has been implemented consisting of systematic measures to ensure that boric acid corrosion does not lead to degradation of the assurance that the reactor coolant pressure boundary will have an extremely low probability of abnormal leakage, rapidly propagating failure, or gross rupture. The program should include the following:

(1) A determination of the principal locations where leaks that are smaller than the allowable technical specification limit can cause degradation of the primary pressure boundary by boric acid corrosion. Particular consideration should be given to identifying those locations where conditions exist that could cause high concentrations of boric acid on pressure boundary surfaces.

(2) Procedures for locating small coolant leaks (i.e., leakage rates at less than technical specification limits). It is important to establish the potential path of the leaking coolant and the reactor pressure boundary components it is likely to contact. This information is important in determining the interaction between the leaking coolant and reactor coo`nt pressure boundary materials.

(3) Methods for conducting examinations and performing engineering evaluations to establish the impact on the reactor coolant pressure boundary when leakage is located. This should include procedures to promptly gather the necessary information for an engineering evaluation before the removal of evidence of leakage, such as boric acid crystal buildup.

(4) Corrective actions to prevent recurrences of this type of corrosion. This should include any modifications to be introduced in the present design or operating procedures of the plant that (a) reduce the probability of primary coolant leaks at the locations where they may cause corrosion damage and (b) entail the use of suitable corrosion resistant materials or the application of protective coatings/claddings.

Additional insight into the phenomena related to boric acid corrosion -- carbon steel components is provided in the attachment to this letter.

The request that licensees provide assurances that a program has been implemented to address the corrosive effects of reactor coolant system leakage at less than technical specification limits constitutes a new staff position. Previous staff positions have not considered the corrosion of external surfaces of the reactor coolant pressure boundary. Based on the frequency and continuing pattern of significant degradation of the reactor coolant pressure boundary that was discussed above, the staff now concludes that in the absence of such a program compliance with General Design Criteria 14, 30 and 31 cannot be ensured.

You are required to submit your response signed under oath or affirmation, as specified in 10 CFR 50.54(f), within 60 days of receipt of this letter. Your response will be used to determine whether your license should be modified, suspended, or revoked. Your response should provide assurances that such a program is in place or provide a schedule for promptly implementing such a program if one is not in place.

This information is required pursuant to 10 CFR 50.54(f) to assess conformance of PWRs with their licensing basis and to determine whether additional NRC action is necessary. The staff does not request submittal of your program. You shall maintain, in auditable form, records of the program and results obtained from implementation of the program and shall make such records available to NRC inspectors upon request.

This request for information is covered by the Office of Management and Budget under Clearance Number 3150-0011, which expires December 31, 1989.

Comments on burden and duplication may be directed to the Office of Management and Budget, Reports Management, Room 3208, New Executive Office Building, Washington, D.C. 20503.

Sincerely,

Frank Miraglia

Frank Miraglia
Associate Director for Projects
Office of Nuclear Reactor Regulation

Attachment:
As stated

BORIC ACID CORROSION OF CARBON STEEL REACTOR COMPONENTS IN PWR PLANTS

Boric acid is used in PWR plants as a reactivity control agent. Its concentration in the reactor coolant ranges between 0 and approximately 1 weight percent. At these concentrations boric acid solutions will not cause significant corrosion even if they come in contact with carbon steel components. In many cases, however, coolant that leaks out of the reactor coolant system loses a substantial volume of its water by evaporation, resulting in the formation of highly concentrated boric acid solutions or deposits of boric acid crystals. These concentrated solutions of boric acid may be very corrosive for carbon steel. This is illustrated by recent test data, tabulated below, which were referenced in NRC Information Notice No. 86-108, Supplement 2.

Concentration of boric acid (percent)	Condition	Temperature (°F)	Corrosion rate mils/month
25	Aerated	200	400
25	Deaerated	200	250
15	Aerated	200	350-400
15-25	Dripping	210	400

If all of the water evaporates and boric acid crystals are formed, the corrosion is less severe. However, boric acid crystals are not completely benign toward carbon steel, and at a temperature of 500°F, corrosion rates of 0.8 to 1.6 mils/month were obtained in the Westinghouse tests referenced in the generic letter. Corrosion by boric acid crystals was observed in Turkey Point Unit 4 where more than 500 pounds of boric acid crystals were found on the reactor vessel head. After these crystals were removed, corrosion of various components on the reactor vessel head was observed.

The most effective way to prevent boric acid corrosion is to minimize reactor coolant leakages. This can be achieved by frequent monitoring of the locations where potential leakages could occur and repairing the leaky components as soon as possible. Review of the locations where leakages have occurred in the past indicates that the most likely locations are (1) valves; (2) flanged connections in steam generator manways, reactor head closure, etc.; (3) primary coolant pumps where leakages occur at cover-to-casing connections as a result of defective gaskets; and (4) defective welds.

In many of these locations the components exposed to boric acid solution are covered by insulation and the leaks may be difficult to detect. If leak detection systems have been installed in the components (e.g., reactor coolant pumps from certain vendors), they should be used to monitor for leakage.

It is important to determine not only the source of the leakage but also the path taken by the leaking fluid by evaluating the mechanism by which leaking boric acid is transported. In some cases boric acid may be entrained in the steam emerging from the opening in the pressure boundary that subsequently condenses inside the insulation thus carrying boric acid to locations that are remote from the source of leakage.

Boric acid corrosion can be classified into two distinct types: (1) corrosion that actually increases the rate of leakage and (2) corrosion that occurs some distance from the source of leakage and hence does not significantly affect the rate of leakage. An example of the first type is the corrosion of fasteners in the reactor coolant pressure boundary, for example, in reactor coolant pumps. This type of corrosion can lead to excessive corrosion of studs. The second type of corrosion can contribute significantly to the degradation of the reactor coolant pressure boundary. At Arkansas Nuclear One Unit 1, a leak developed in a high pressure injection isolation valve located 8 feet above the high pressure injection nozzle which was made of carbon steel. Accumulation of boric acid resulted in an approximately 1/2-inch-deep corrosion wastage adjacent to the stainless-to-carbon steel weld. Other locations of the nozzle exhibited corrosion to a lesser degree. Corrosion of the reactor vessel head was observed at Salem Unit 2. Corrosion pits were 1 to 3 inches in diameter and 40 to 300 mils deep. The source of this corrosion was a defective seal weld in one of the instrument penetrations. These examples indicate that the corrosion produced by boric acid could degrade even relatively bulky components. At Fort Calhoun, the diameter of a reactor coolant pump closure bolt was reduced from 3.5 inches to 1.1 inches by boric acid corrosion. At San Onofre Unit 2, boric acid corrosion of the valve bolts was responsible for the failure of the valve and the discharge of 18,000 gallons of primary coolant into the containment.

Because of the nature of the corrosion produced by boric acid, the most reliable method of inspection of components is by visual examination. Ultrasonic testing performed in accordance with Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code may not be sensitive enough to detect the wastage. At Fort Calhoun, two successive ultrasonic tests failed to detect corrosion of the reactor pump closure studs. When ultrasonic testing is used, the licensee should provide assurances that the results are reliable.

Reference F

OMB Control No.: 3150-0012

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

August 3, 2001

NRC BULLETIN 2001-01: CIRCUMFERENTIAL CRACKING OF REACTOR PRESSURE VESSEL HEAD PENETRATION NOZZLES

Addressees

All holders of operating licenses for pressurized water nuclear power reactors, except those who have ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to:

(1) request that addressees provide information related to the structural integrity of the reactor pressure vessel head penetration (VHP) 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

(2) require that all addressees provide to the NRC a written response in accordance with the provisions of 10 CFR 50.54(f).

Background

The recent discoveries of cracked and leaking Alloy 600 VHP nozzles, including control rod drive mechanism (CRDM) and thermocouple nozzles, at four pressurized water reactors (PWRs) have raised concerns about the structural integrity of VHP nozzles throughout the PWR industry. Nozzle cracking at Oconee Nuclear Station Unit 1 (ONS1) in November 2000 and Arkansas Nuclear One Unit 1 (ANO1) in February 2001 was limited to axial cracking, an occurrence deemed to be of limited safety concern in the NRC staff's generic safety evaluation on the cracking of VHP nozzles, dated November 19, 1993. However, the discovery of circumferential cracking at Oconee Nuclear Station Unit 3 (ONS3) in February 2001 and Oconee Nuclear Station Unit 2 (ONS2) in April 2001 – particularly the large circumferential cracking identified in two CRDM nozzles at ONS3 – has raised concerns about the potential safety implications and prevalence of cracking in VHP nozzles in PWRs.

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As described in NRC Information Notice (IN) 2001-05, "Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3," dated April 30, 2001, Duke Energy Corporation (the licensee) performed a visual examination (VT-2) on the outer surface of the reactor pressure vessel (RPV) head at ONS3 to inspect for indications of borated water leakage, as part of normal surveillance during a planned maintenance outage. This visual examination followed cleaning of the RPV head during the prior outage to remove all existing boric acid deposits (from other sources such as leaking CRDM flanges) that could mask the identification of subsequent deposits that would be indicative of new or ongoing leakage. The VT-2 examination revealed small amounts of boric acid deposits (less than 1 cubic inch) at locations where the CRDM nozzles exit the RPV head for 9 of the 69 CRDM nozzles. Subsequent nondestructive examination (NDE) identified 47 recordable crack indications in the 9 degraded CRDM nozzles. The licensee initially characterized these flaws as being axial and a part of the RPV pressure boundary, or below-the-weld circumferential indications (which are not part of the RPV pressure boundary), and initiated repairs of the degraded areas.

Subsequent dye-penetrant testing (PT) of the repaired areas revealed the presence of additional indications in two of the nine degraded nozzles. While repairing the indications in these two nozzles, the licensee found that each nozzle had a circumferential crack that extended about 165° around the nozzle, above the weld (i.e., at a location that is part of the RPV pressure boundary). Further investigation and metallurgical examination identified that these cracks had initiated from the outside diameter (OD) of the CRDM nozzles. The circumferential crack in one of the nozzles was through-wall, and the crack in the other nozzle had pin hole indications on the nozzle inside diameter (ID). These cracks followed the contour of the weld profile.

The licensee stated that pre-repair ultrasonic testing (UT) examinations had identified indications in these areas, but that these indications had been misinterpreted as inconsequential craze cracking with unusual characteristics. The characterizations of these two nozzle indications were subsequently revised following the initial post-repair PT examinations. The licensee concluded that the root cause of the CRDM nozzle cracking was primary water stress corrosion cracking (PWSCC). The cracking initiated at the OD of the nozzles after cracking of the J-groove weld (see below) or adjacent heat-affected zone metal permitted coolant leakage into the annular region between the CRDM nozzle and the RPV head. This conclusion was based on metallurgical examinations, crack location and orientation, and finite element analyses.

The CRDM nozzles at ONS3 are approximately 5 feet long and are J-groove welded to the inner radius of the RPV head, with the lower end of each nozzle extending about 6 inches below the inside of the RPV head (see Attachment). The nozzles are constructed from 4-inch OD Alloy 600 Inconel procured in accordance with the requirements of Specification SB-167 to the 1965 Edition, including Addenda through the Summer 1967 Addenda, of Section II of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code. The weld preparation for the installation of each nozzle in the RPV head was accomplished by machining and buttering the J-groove with Alloy 182 weld metal. The RPV head was subsequently stress relieved and then the final machining of the CRDM penetrations, including the counterbore, was accomplished. Each nozzle was then machined to final dimensions to assure the appropriate design interference fit between the RPV head bore and the OD of the nozzle. The interference fit of the CRDM nozzles was made using a shrink fit process to install the CRDM nozzles. In this process, the nozzles were cooled to at least -140°F; they were then inserted into the closure head penetration, and the entire assembly was allowed to warm to room temperature (70°F minimum). The CRDM nozzles were tack welded and then permanently welded to the closure head using Alloy 182 weld metal. The manual shielded metal arc welding (SMAW) process was used for both the tack weld and the J-groove weld. During weld buildup, the weld was ground and PT inspected at each 9/32 inch of the weld. The final weld surface was ground and PT inspected.

The design and fabrication process for the VHPs in all PWR plants is similar to that described for ONS3.

Since the issuance of NRC IN 2001-05, circumferential cracking was identified in another CRDM nozzle, at ONS2. During a visual examination of the RPV head, Duke Energy Corporation identified boric acid deposits in the vicinity of four CRDM nozzles at ONS2. Subsequent UT examination identified a single CRDM nozzle with one OD-initiated circumferential crack, having a crack depth of 0.070 inch (~11% through-wall) and a length of 1.26 inches (~10% of the circumference).

Cracking due to PWSCC in PWR CRDM nozzles and other VHP nozzles fabricated from Alloy 600 is not a new issue; axial cracking in the CRDM nozzles has been identified since the late 1980s. In addition, numerous small-bore Alloy 600 nozzles and pressurizer heater sleeves have experienced leaks attributable to PWSCC. Generally, these components are exposed to high temperatures (greater than 550°F) and a primary water environment. However, circumferential cracking from the nozzle OD to the ID, above the weld, and cracking of the J-groove weld have not been previously identified in PWRs.

As described in Generic Letter (GL) 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," dated April 1, 1997, an action plan was implemented by the NRC staff in 1991 to address PWSCC of Alloy 600 VHP nozzles at all operating U.S. PWRs. After reviewing safety assessments submitted by the industry and examining overseas inspection findings, the NRC staff concluded in its generic safety evaluation that CRDM nozzle and weld cracking in PWRs was not an immediate safety concern. The basis for this conclusion was that if PWSCC occurred (1) the cracks would be predominately axial in orientation, (2) the axial cracks would result in detectable leakage before catastrophic failure (with the expectation that CRDM nozzle cracking would result in a substantial volume of leaking coolant) and (3) the expected large amount of leakage would be detected during visual examinations performed as part of surveillance walkdown inspections before significant damage to the RPV head occurred. The safety evaluation identified concerns about potential circumferential cracking (which would need to be addressed on a plant-specific basis) as a consequence of high residual stresses resulting from initial manufacture and the impact of tube straightening that may have been needed after welding. The safety evaluation also noted the need for enhanced leakage monitoring.

The generic responses of licensees to GL 97-01 were predicated on the development of susceptibility ranking models to relate the operating conditions (in particular the operating temperature and time) for each plant to the plant's relative susceptibility to PWSCC. The generic responses committed to surface examinations of the VHP nozzles at the plants identified as having the highest relative susceptibility ranking. Consistent with the expectations expressed by the NRC staff in GL 97-01, the surface examinations conducted prior to November 2000 identified only limited axial cracking, and circumferential cracking below the weld in the base metal of CRDM nozzles, but no circumferential cracking above the nozzle welds and no cracking in the Alloy 182 welds.

<u>Discussion</u>

The recent identification of circumferential cracking in CRDM nozzles at ONS2 and ONS3, along with axial cracking in the J-groove welds at these two units and at ONS1 and ANO1, has resulted in the staff reassessing its conclusion in GL 97-01 that cracking of VHP nozzles is not an immediate safety concern. Specifically, the findings indicate that circumferential cracks outside of the J-groove welds can occur, in contrast to an earlier conclusion that the cracks would be predominantly axial in orientation. The findings indicate that cracking of the J-groove weld metal can precede cracking of the base metal. These findings raise questions regarding the industry approach, developed in generic responses to GL 97-01, that utilizes PWSCC susceptibility modeling based on the base metal conditions and do not consider those of the weld metal. In addition, the presence of circumferential cracking at ONS3, where only a small amount of boric acid residue indicated a problem, calls into question the adequacy of current visual examinations for detecting either axial or circumferential cracking in VHP nozzles. This is especially significant if prior existing boric acid deposits on the RPV head mask the identification of new deposits. Also, the presence of insulation on the RPV head or other impediments may restrict an effective visual examination. As a remedial measure, the RPV head may have to be cleaned at a prior outage for effective identification of new deposits from VHP nozzle cracking if new deposits cannot be discriminated from existing deposits from other sources. However, the NRC staff believes that boric acid deposits that cannot be dispositioned as coming from another source should be considered, as a conservative assumption, to be from VHP nozzles, and appropriate corrective actions may be necessary. In addition, the use of special tooling or procedures may be required to provide assurance that the visual examinations will be effective in detecting the relevant conditions.

One function of VHP nozzles is to maintain the reactor coolant system pressure boundary. The CRDM nozzles support and guide the control rods, and, therefore, are relied upon in shutting down the reactor. Cracking of CRDM nozzles and welds is a degradation of the reactor coolant system boundary. Industry experience has shown that Alloy 600 is susceptible to stress corrosion cracking. Further, the findings at ONS2 and ONS3 highlight the possible existence of a more aggressive environment in the CRDM housing annulus following through-wall leakage; potentially highly concentrated borated primary water could become oxygenated in this annulus and possibly cause increased propensity for the initiation of cracking and higher crack growth rates.

The cracking identified at ONS2 and ONS3 reinforces the importance of conducting effective examinations of the RPV upper 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 using appropriate NDE methods (such as PT, UT, and eddy-current testing) to adequately characterize cracks. Because of plant-specific design characteristics, there is no uniform way to perform effective visual examinations of the RPV head at PWR facilities. Some plants have the head insulation sufficiently offset from the RPV head to permit an effective visual examination. Other plants have the insulation offset from the head but in a contour matching that of the head, requiring special tooling and procedures to perform an effective visual examination. Still other plants have insulation directly adjacent to or attached to the RPV head, potentially requiring the removal of the insulation to permit an effective visual examination. Several licensees have recently performed expanded VT-2 examinations using remote devices to inspect between the RPV head and the insulation. One aspect of conducting effective visual examinations that is common to all PWR plants is the need to successfully distinguish boric acid deposits originating with VHP nozzle cracking from deposits that are attributable to other sources.

For boric acid deposits from CRDM nozzle cracks to be detectable at the outer surface of the RPV head, sufficient reactor coolant has to leak through the primary pressure boundary into the annulus between the CRDM nozzle and the RPV head base metal, propagate up the annulus, and finally emerge onto the outer surface of the RPV head. Since PWSCC cracks in Alloy 600 and Alloy 182 welds are very tight, leakage from axial cracks in the nozzle and their associated welds is expected to be small. In addition, possible restraint of pressure-induced bending of circumferential cracks in CRDM nozzles could minimize the leakage available even from CRDM nozzles with large circumferential cracks, as evidenced by small boric acid deposits identified at ONS3. As described in Electric Power Research Institute (EPRI) Report TP-1001491, Part 2, "PWR Materials Reliability Program Interim Alloy 600 Safety Assessments for US PWR Plants (MRP-44), Part 2: Reactor Vessel Top Head Penetrations" (referred to as "the MRP-44, Part 2, report"), the majority of CRDM nozzles are installed into the RPV head with an interference fit at room temperature, with 43 plants having specified interference fit ranges greater than those at ONS and ANO1. Should these interference fits persist at plant operating conditions, they could provide an impediment to the flow of coolant leakage up the annulus and thereby limit the amount of deposit available on the RPV head for detection by visual examination.

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. This finding raises an issue regarding the adequacy of cracking susceptibility models based only on the base metal conditions.

(2) The identification of cracking at ANO1 raises an issue regarding the adequacy of the industry's GL 97-01 susceptibility model. ANO1 cracking was predicted to be more than 15 effective full power years (EFPY) beyond January 1, 1997, from reaching the same conditions as the limiting plant, based on the susceptibility models used by the industry to address base metal cracking in response to GL 97-01.

(3) Circumferential cracking of CRDM nozzles, located outside of any structural retaining welds, has been identified for the first time. This finding raises concerns about the potential for rapidly propagating failure of CRDM nozzles and control rod ejection, causing a loss of coolant accident (LOCA).

(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 effects 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.

After the initial finding of significant circumferential cracking at ONS3, the NRC held a public meeting with the EPRI Materials Reliability Program (MRP) on April 12, 2001, to discuss CRDM nozzle circumferential cracking issues. During the meeting, the industry representatives indicated that they were developing a generic safety assessment, recommendations for revisions of near-term inspections, and long-term inspection and flaw evaluation guidelines. On May 18, 2001, the MRP submitted the MRP-44, Part 2, report to provide an interim safety assessment for PWSCC of Alloy 600 VHP nozzles and Alloy 182 J-groove welds in PWR plants. On June 7, 2001, the NRC held a public meeting at which the MRP provided initial responses to questions on the MRP-44, Part 2, report that the NRC staff had identified and transmitted to the MRP on May 25, 2001.

The approach taken in the MRP-44, Part 2, report uses an assessment of the relative susceptibility of each PWR to OD-initiated or weld PWSCC based on the operating time and temperature of the penetrations. Based upon this simplified model, provided in Appendix B of the MRP-44, Part 2, report, each PWR plant was ranked by the MRP according to the operating time in EFPY required for the plant to reach an effective time-at-temperature equivalent to ONS3 at the time the above-weld circumferential cracks were identified in early 2001. To address the experience at ONS, the report recommended that plants ranked within 10 EFPY of ONS3 and having fall 2001 outages should perform a visual inspection of the RPV top head capable of detecting small amounts of leakage similar to that observed at the Oconee units and ANO1.

The NRC staff provided questions to the MRP on various aspects of the MRP-44, Part 2, report in a letter dated June 22, 2001; the MRP provided responses in a letter dated June 29, 2001. These questions addressed aspects of the proposed industry treatment that the NRC staff did not agree with. Two specific areas of concern are (1) the finding that nozzle leaks are detectable on all vessel heads, and (2) the lack of consideration of an applicable crack growth rate for the VHP nozzle cracking situation (including a conclusion in the MRP responses that the appropriate crack growth rate for OD cracking of VHP nozzles is represented by data from a primary water environment). The issue of detectibility of nozzle leaks in any particular plant is difficult to address due to a need for plant-specific as-built geometries, such as measured dimensions on CRDM nozzles and RPV penetrations to characterize the interference fit population for a particular RPV head. In addition, there is a need to provide a sufficiently detailed model of the RPV head and expected through-wall crack characteristics, such as surface roughness and crack tightness, to provide assurance that any nozzles with through-wall cracking will provide sufficient leakage to the RPV head surface such that residual deposits of boric acid will provide a detectable condition for the visual examination. An inability to provide assurance of a detectable residual deposit or to discriminate prior existing boric acid deposits caused by non-safety-significant sources from boric acid deposits caused by CRDM nozzle cracking could limit the effectiveness of visual examinations.

Because visual examination of the RPV head or volumetric examination of the VHP nozzles occurs only periodically (generally at a scheduled refueling outage), the issue of crack growth rate in VHP nozzles is an important consideration in providing assurance that VHP nozzles will maintain their structural integrity between examination opportunities. In particular, crack growth should be low enough to ensure that VHP nozzles which are determined to be unflawed during an examination do not have critical flaw sizes prior to the next scheduled examination.

From the results of the susceptibility ranking model proposed in Appendix B to MRP-44, Part 2, the population of PWR plants can be divided into several subpopulations with similar characteristics:

- those plants which have demonstrated the existence of PWSCC in their VHP nozzles (through the detection of boric acid deposits) and for which cracking can be expected to recur and affect additional VHPs;
- those plants which can be considered as having a high susceptibility to PWSCC based upon a susceptibility ranking of less than 5 EFPY from the ONS3 condition;
- those plants which can be considered as having a moderate susceptibility to PWSCC based upon a susceptibility ranking of more than 5 EFPY but less than 30 EFPY from the ONS3 condition; and
- the balance of plants which can be considered as having low susceptibility based upon a susceptibility ranking of more than 30 EFPY from the ONS3 condition.

Although the industry susceptibility ranking model has limitations, such as large uncertainties and no predictive capability, the model does provide a starting point for assessing the potential for VHP nozzle cracking in PWR plants.

The following paragraphs characterize the gradation of inspection effort for the subpopulations of plants noted above. Nevertheless, addressees should be cognizant of extenuating circumstances at their respective plant(s) that would suggest a need for more aggressive inspection practices to provide an appropriate level of confidence in VHP nozzle integrity. In addition, since inspection and repair activities can potentially result in large personnel exposures, licensees should ensure that all activities related to the inspection of VHP nozzles and the repair of identified degradation are planned and implemented to keep personnel exposures as low as reasonably achievable (ALARA), consistent with the NRC ALARA policy.

For the subpopulation of plants considered to have a low susceptibility to PWSCC, based upon a susceptibility ranking of more than 30 EFPY from the ONS3 condition, the anticipated low likelihood of PWSCC degradation at these facilities indicates that enhanced examination beyond the current requirements is not necessary at the present time because there is a low likelihood that the enhanced examination would provide additional evidence of the propensity for PWSCC in VHP nozzles.

For the subpopulation of plants considered to have a moderate susceptibility to PWSCC based upon a susceptibility ranking of more than 5 EFPY but less than 30 EFPY from the ONS3 condition, an effective visual examination, at a minimum, of 100% of the VHP nozzles that is capable of detecting and discriminating small amounts of boric acid deposits from VHP nozzle leaks, such as were identified at ONS2 and ONS3, may be sufficient to provide reasonable confidence that PWSCC degradation would be identified prior to posing an undue risk. This effective visual examination should not be compromised by the presence of insulation, existing deposits on the RPV head, or other factors that could interfere with the detection of leakage.

For the subpopulation of plants considered to have a high susceptibility to PWSCC based upon a susceptibility ranking of less than 5 EFPY from the ONS3 condition, the possibility of VHP nozzle cracking at one of these facilities indicates the need to use a qualified visual examination of 100% of the VHP nozzles. This qualified visual examination should be able to reliably detect and accurately characterize leakage from cracking in VHP nozzles considering two characteristics. One characteristic is a plant-specific demonstration that any VHP nozzle exhibiting through-wall cracking will provide sufficient leakage to the RPV head surface (based on the as-built configuration of the VHPs). Secondly, similar to the effective visual examination for moderate susceptibility plants, the effectiveness of the qualified visual examination should not be compromised by the presence of insulation, existing deposits on the RPV head, or other factors that could interfere with the detection of leakage. Absent the use of a qualified visual examination, a qualified volumetric examination of 100% of the VHP nozzles (with a demonstrated capability to reliably detect cracking on the OD of a VHP nozzle) may be appropriate to provide evidence of the structural integrity of the VHP nozzles.

For the subpopulation of plants which have already identified the existence of PWSCC in the CRDM nozzles (for example, through the detection of boric acid deposits), there is a sufficient likelihood that the cracking of VHP nozzles will continue to occur as the facilities continue to operate. Therefore, a qualified volumetric examination of 100% of the VHP nozzles (with a demonstrated capability to reliably detect cracking on the OD of the VHP nozzle) may be appropriate to provide evidence of the structural integrity of the VHP nozzles.

The NRC has developed a Web page to keep the public informed of generic activities on PWR Alloy 600 weld cracking (http://www.nrc.gov/NRC/REACTOR/ALLOY-600/index.html). This page provides links to information regarding the cracking identified to date, along with documentation of NRC interactions with industry (industry submittals, meeting notices, presentation materials, and meeting summaries). The NRC will continue to update this Web page as new information becomes available.

Applicable Regulatory Requirements

Several provisions of the NRC regulations and plant operating licenses (Technical Specifications) pertain to the issue of VHP nozzle cracking. The general design criteria (GDC) for nuclear power plants (Appendix A to 10 CFR Part 50), or, as appropriate, similar requirements in the licensing basis for a reactor facility, the requirements of 10 CFR 50.55a, and the quality assurance criteria of Appendix B to 10 CFR Part 50 provide the bases and requirements for NRC staff assessment of the potential for and consequences of VHP nozzle cracking.

The applicable GDC include GDC 14, GDC 31, and GDC 32. GDC 14 specifies that the reactor coolant pressure boundary (RCPB) have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture; the presence of cracked and leaking VHP nozzles is not consistent with this GDC. GDC 31 specifies that the probability of rapidly propagating fracture of the RCPB be minimized; the presence of cracked and leaking VHP nozzles is not consistent with this GDC. GDC 32 specifies that components which are part of the RCPB have the capability of being periodically inspected to assess their structural and leaktight integrity; inspection practices that do not permit reliable detection of VHP nozzle cracking are not consistent with this GDC.

NRC regulations at 10 CFR 50.55a state that ASME Class 1 components (which include VHP nozzles) must meet the requirements of Section XI of the ASME Boiler and Pressure Vessel Code. Table IWA-2500-1 of Section XI of the ASME Code provides examination requirements for VHP nozzles and references IWB-3522 for acceptance standards. IWB-3522.1(c) and (d) specify that conditions requiring correction include the detection of leakage from insulated components and discoloration or accumulated residues on the surfaces of components, insulation, or floor areas which may reveal evidence of borated water leakage, with leakage defined as "the through-wall leakage that penetrates the pressure retaining membrane." Therefore, 10 CFR 50.55a, through its reference to the ASME Code, does not permit through-wall cracking of VHP nozzles.

For through-wall leakage identified by visual examinations in accordance with the ASME Code, acceptance standards for the identified degradation are provided in IWB-3142. Specifically, supplemental examination (by surface or volumetric examination), corrective measures or repairs, analytical evaluation, and replacement provide methods for determining the acceptability of degraded components.

Criterion IX of Appendix B to 10 CFR Part 50 states that special processes, including nondestructive testing, shall be controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements. Within the context of providing assurance of the structural integrity of VHP nozzles, special requirements for visual examination would generally require the use of a qualified visual examination method. Such a method is one that a plant-specific analysis has demonstrated will result in sufficient leakage to the RPV head surface for a through-wall crack in a VHP nozzle, and that the resultant leakage provides a detectable deposit on the RPV head. The analysis would have to consider, for example, the as-built configuration of the VHPs and the capability to reliably detect and accurately characterize the source of the leakage, considering the presence of insulation, preexisting deposits on the RPV head, and other factors that could interfere with the detection of leakage. Similarly, special requirements for volumetric examination would generally require the use of a qualified volumetric examination method, for example, one that has a demonstrated capability to reliably detect cracking on the OD of the VHP nozzle above the J-groove weld.

Criterion V of Appendix B to 10 CFR Part 50 states that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Criterion V further states that instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Visual and volumetric examinations of VHP nozzles are activities that should be documented in accordance with these requirements.

Criterion XVI of Appendix B to 10 CFR Part 50 states that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. For significant conditions adverse to quality, the measures taken shall include root cause determination and corrective action to preclude repetition of the adverse conditions. For cracking of VHP nozzles, the root cause determination is important to understanding the nature of the degradation present and the required actions to mitigate future cracking. These actions could include proactive inspections and repair of degraded VHP nozzles.

Plant technical specifications pertain to the issue of VHP nozzle cracking insofar as they require no through-wall reactor coolant system leakage.

Requested Information

This bulletin requests addressees to submit information. Addressees who choose to utilize the analyses provided in the MRP-44, Part 2, report or similar analyses need to consider the NRC staff questions relative to this report (provided to the MRP by letter dated June 22, 2001) when preparing their plant-specific responses to the requested information. Addressees should note that the NRC staff has found that the industry response to these questions (provided by letter dated June 29, 2001) does not provide a sufficient basis for resolving the relevant technical issues and that additional information will be necessary to support the plant-specific evaluations.

Addressees are requested to provide the requested information within 30 days of the date of this bulletin (except for Item 5).

1. All addressees are requested to provide the following information:

    a. the plant-specific susceptibility ranking for your plant(s) (including all data used to determine each ranking) using the PWSCC susceptibility model described in Appendix B to the MRP-44, Part 2, report;

    b. a description of the VHP nozzles in your plant(s), including the number, type, inside and outside diameter, materials of construction, and the minimum distance between VHP nozzles;

    c. a description of the RPV head insulation type and configuration;

    d. a description of the VHP nozzle and RPV head inspections (type, scope, qualification requirements, and acceptance criteria) that have been performed at your plant(s) 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;

    e. a description of the configuration of the missile shield, the CRDM housings and their support/restraint system, and all components, structures, and cabling from the top of the RPV head up to the missile shield. Include the elevations of these items relative to the bottom of the missile shield.

2. If your plant has previously experienced either leakage from or cracking in VHP nozzles, addressees are requested to provide the following information:

    a. a description of the extent of VHP nozzle leakage and cracking detected at your plant, including the number, location, size, and nature of each crack detected;

    b. 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;

    c. your plans for future inspections (type, scope, qualification requirements, and acceptance criteria) and the schedule;

    d. your basis for concluding that the inspections identified in 2.c will assure that regulatory requirements are met (see Applicable Regulatory Requirements section). Include the following specific information in this discussion:

        (1) If your future inspection plans do not include performing inspections before December 31, 2001, provide your basis for concluding that the regulatory requirements discussed in the Applicable Regulatory Requirements section will continue to be met until the inspections are performed.

        (2) If your future inspection plans do not include volumetric examination of all VHP nozzles, provide your basis for concluding that the regulatory requirements discussed in the Applicable Regulatory Requirements section will be satisfied.

3. If the susceptibility ranking for your plant is within 5 EFPY of ONS3, addressees are requested to provide the following information:

   a. your plans for future inspections (type, scope, qualification requirements, and acceptance criteria) and the schedule;

   b. your basis for concluding that the inspections identified in 3.a. will assure that regulatory requirements are met (see Applicable Regulatory Requirements section). Include the following specific information in this discussion:

      (1) If your future inspection plans do not include performing inspections before December 31, 2001, provide your basis for concluding that the regulatory requirements discussed in the Applicable Regulatory Requirements section will continue to be met until the inspections are performed.

      (2) If your future inspection plans include only visual inspections, discuss the corrective actions that will be taken, including alternative inspection methods (for example, volumetric examination), 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 information:

   a. your plans for future inspections (type, scope, qualification requirements, and acceptance criteria) and the schedule;

   b. your basis for concluding that the inspections identified in 4.a will assure that regulatory requirements are met (see Applicable Regulatory Requirements section). Include the following specific information in this discussion:

      (1) If your future inspection plans do not include a qualified visual examination at the next scheduled refueling outage, provide your basis for concluding that the regulatory requirements discussed in the Applicable Regulatory Requirements section will continue to be met until the inspections are performed.

      (2) The corrective actions that will be taken, including alternative inspection methods (for example, volumetric examination), if leakage is detected.

5. Addressees are requested to provide the following information within 30 days after plant restart following the next refueling outage:

   a. a description of the extent of VHP nozzle leakage and cracking detected at your plant, including the number, location, size, and nature of each crack detected;

b. if cracking is identified, a description of the inspections (type, scope, qualification requirements, and acceptance criteria), 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 in accordance with this bulletin.

Required Response

In accordance with 10 CFR 50.54(f), in order to determine whether any license should be modified, suspended, or revoked, each addressee is required to respond as described below. This information is sought to verify licensee compliance with the current licensing basis for the facilities covered by this bulletin.

Within 30 days of the date of this bulletin, each addressee is required to submit a written response indicating (1) whether the requested information will be submitted and (2) whether the requested information will be submitted within the requested time period. Addressees who choose not to submit the requested information, or are unable to satisfy the requested completion date, must describe in their response any alternative course of action they propose to take, including the basis for the acceptability of the proposed alternative course of action.

The required written response should be addressed to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, under oath or affirmation under the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50. 54(f). In addition, submit a copy of the response to the appropriate regional administrator.

Reasons for Information Request

Through-wall cracking of VHP nozzles violates NRC regulations and plant technical specifications. Circumferential cracking of VHP nozzles can pose a safety risk if permitted to progress to the point that nozzle integrity is in question and the risk of a loss of coolant accident or probability of a VHP nozzle ejection increases. This information request is necessary to permit the assessment of plant-specific compliance with NRC regulations. This information will also be used by the NRC staff to determine the need for and to guide the development of additional regulatory actions to address cracking in VHP nozzles. Such regulatory actions could include regulatory requirements for augmented inspection programs under 10 CFR 55a(g)(6)(ii) or additional generic communication.

Related Generic Communications

- Information Notice 2001-05, "Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3," April 30, 2001. [ADAMS Accession No. ML011160588]

- Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," April 1, 1997.
- Information Notice 96-11, "Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations," February 14, 1996.
- Information Notice 90-10, "Primary Water Stress Corrosion Cracking of INCONEL 600," February 23, 1990.
- Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," March 17, 1988.
- NUREG/CR-6245, "Assessment of Pressurized Water Reactor Control Rod Drive Mechanism Nozzle Cracking," October 1994.

Backfit Discussion

Under the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f), this generic letter transmits an information request for the purpose of verifying compliance with existing applicable regulatory requirements (see the Applicable Regulatory Requirements section of this bulletin). Specifically, the requested information will enable the NRC staff to determine whether current inspection practices for the detection of cracking in the VHP nozzles at reactor facilities provide reasonable confidence that reactor coolant pressure boundary integrity is being maintained. The requested information will also enable the NRC staff to determine whether addressee inspection practices need to be augmented to ensure that the safety significance of VHP nozzle cracking remains low. No backfit is either intended or approved by the issuance of this bulletin, and the staff has not performed a backfit analysis.

Federal Register Notification

A notice of opportunity for public comment on this bulletin was not published in the *Federal Register* because the NRC staff is requesting information from power reactor licensees on an expedited basis for the purpose of assessing compliance with existing applicable regulatory requirements and the need for subsequent regulatory action. This bulletin was prompted by the discovery of circumferential cracking in CRDM nozzles (above the nozzle-to-vessel head weld) from the OD to the ID and cracking in the J-groove weld metal itself. Both of these phenomena have not been previously identified in PWRs. As the resolution of this matter progresses, the opportunity for public involvement will be provided.

Paperwork Reduction Act Statement

This bulletin contains information collections that are subject to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.) These information collections were approved by the Office of Management and Budget, approval number 3150-0011.

The burden to the public for these mandatory information collections is 140 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the information collection. Send comments regarding this burden estimate or on any other aspect of these information collections, including suggestions for reducing the burden, to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by Internet electronic mail to BJS1@NRC.GOV; and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0011), Office of Management and Budget, Washington, DC 20503.

Public Protection Notification

If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

If you have any questions about this matter, please contact the technical contact listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

/RA/

David B. Matthews, Director
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Technical Contact: Allen L. Hiser, Jr., NRR
301-415-1034
E-mail: alh1@nrc.gov

Lead Project Manager: Jacob I. Zimmerman, NRR
301-415-2426
E-mail: jiz@nrc.gov

Attachment:
Schematic Figure of Typical CRDM Nozzle Penetration

Paperwork Reduction Act Statement

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David B. Matthews, Director
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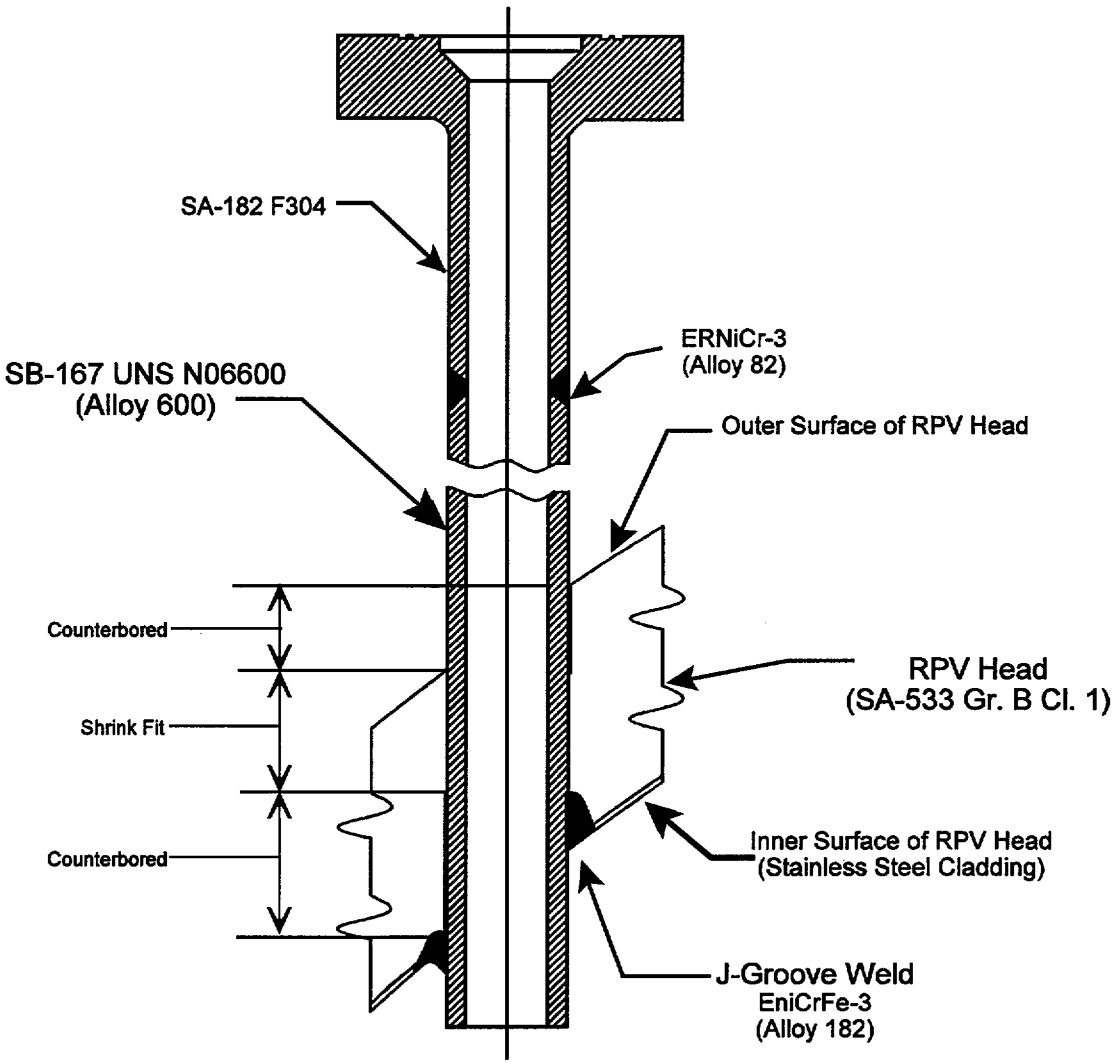
Attachment:
Schematic Figure of Typical CRDM Nozzle Penetration
*See previous concurrence
Accession No.: ML01208284 Template No.:

OFFICE	EMCB: DE	C:EMCB	D:DE	C:REXB	D:DRIP
NAME	AHiser*	WBateman*	JStrosnider*	LMarsh	DMatthews
DATE	08/2/2001	08/2/2001	08/2/2001	08/2/2001	08/2/2001

OFFICIAL RECORD COPY



Schematic Figure of Typical CRDM Nozzle Penetration

Reference G

OMB Control No.: 3150-0012

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, DC 20555-0001

March 18, 2002

NRC BULLETIN 2002-01: REACTOR PRESSURE VESSEL HEAD DEGRADATION AND REACTOR COOLANT PRESSURE BOUNDARY INTEGRITY

Addressees

All holders of operating licenses for pressurized-water nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor pressure vessel, and all holders of operating licenses for boiling-water reactors for information.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to require pressurized-water reactor (PWR) addressees to submit:

(1) information related to the integrity of the reactor coolant pressure boundary including the 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 in accordance with the provisions of Title 10, Section 50.54(f), of the *Code of Federal Regulations* (10 CFR 50.54(f)) if they are unable to provide the information or they can not meet the requested completion dates.

Background

On August 3, 2001, the NRC issued Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles" (ADAMS Accession Number ML012080284). That bulletin described instances of cracked and leaking Alloy 600 reactor pressure vessel head penetration nozzles, including control rod drive mechanism and thermocouple nozzles. In response to that bulletin, pressurized-water reactor licensees provided their plans for inspecting their reactor pressure vessel head penetrations and/or the outside surface of the reactor pressure vessel head to determine whether the nozzles were leaking. Some plants have completed these inspections.

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In conducting these inspections at the Davis-Besse Nuclear Power Station in February and March 2002, the licensee identified three control rod drive mechanism nozzles with indications of axial cracking that resulted in reactor coolant pressure boundary leakage. One of these three control rod drive mechanism nozzles also had a circumferential indication which was not through-wall, and therefore, did not result in reactor coolant pressure boundary leakage. These were not unexpected findings, given the high susceptibility of the Davis-Besse plant to vessel head penetration nozzle cracking (as described in NRC Bulletin 2001-01). These axial indications were identified in control rod drive mechanism nozzles 1, 2, and 3, which are located near the center of the reactor pressure vessel head. Because of these indications, the licensee decided to repair control rod drive mechanism nozzles 1, 2, and 3, as well as two other nozzles that had indications but had not resulted in reactor coolant pressure boundary leakage.

The repair process for these nozzles included roll expanding the control rod drive mechanism nozzle material into the surrounding reactor pressure vessel head material, followed by machining along the axis of the control rod drive mechanism nozzle to an elevation above the indications in the nozzle material. On March 6, 2002, the machining process on control rod drive mechanism nozzle 3 was prematurely terminated and the machining apparatus was removed from the nozzle. During the removal process, control rod drive mechanism nozzle 3 was mechanically agitated and subsequently displaced, or tipped, in the downhill direction (away from its vertical position on top of the dome-shaped reactor pressure vessel head) until its flange contacted the flange of the adjacent control rod drive mechanism nozzle.

To identify the cause of the control rod drive mechanism nozzle displacement, the licensee began an investigation into the condition of the reactor pressure vessel head surrounding control rod drive mechanism nozzle 3. This investigation included removing the nozzle and boric acid deposits from the reactor pressure vessel head, and ultrasonically measuring the thickness of the reactor pressure vessel head in the vicinity of control rod drive mechanism nozzles 1, 2, and 3. Upon completing the boric acid removal on March 7, 2002, the licensee conducted a visual examination of the area, which identified a cavity in the reactor pressure vessel head on the downhill side of control rod drive mechanism nozzle 3 (i.e., the lowest portion of the nozzle extending out of the reactor pressure vessel head). Follow-up characterization by ultrasonic testing indicated thinning of the reactor pressure vessel head material adjacent to the nozzle. The thinned area was initially estimated to extend approximately 5 inches from the penetration for control rod drive mechanism nozzle 3; however, from more recent results, the thinned area extends approximately 7 inches from the nozzle at the stainless steel cladding, indicating the degradation was more severe at the bottom of the cavity than on the top. The width of the exposed area was approximately 4 to 5 inches at its widest part. The minimum remaining thickness of the reactor pressure vessel head in the thinned area was found to be approximately 3/8-inch. This thickness was attributed to the thickness of the stainless steel cladding on the inside surface of the reactor pressure vessel head, which is nominally 3/8-inch thick.

NRC Information Notice 2002-11, "Recent Experience with Degradation of Reactor Pressure Vessel Head," dated March 12, 2002, provides additional detail concerning the Davis-Besse inspection findings, the design and configuration of the Davis-Besse reactor pressure vessel head and service structure, and past inspections.

Since the NRC issued Information Notice 2002-11, additional information has become available concerning the condition of the reactor pressure vessel head at Davis-Besse. Specifically, the 3/8-inch stainless steel cladding near control rod drive mechanism nozzle 3 was found to be deflected upwards by about 1/8-inch over a 4-inch distance, indicating that the material had yielded. This is significant because the 3/8-inch cladding had essentially become the reactor coolant pressure boundary near the affected nozzle after the base material of the reactor pressure vessel head had degraded.

In addition, two areas of less severe thinning have been detected near control rod drive mechanism nozzle 2. At the time this bulletin was being prepared, it was not known whether these two areas were connected because one was detected on the outer surface of the reactor pressure vessel head and the other was detected at the inner surface. In addition, the dimensions of these areas were not known at the time this bulletin was being prepared. On the basis of preliminary information, the affected area appeared to be much smaller in size than the area located near control rod drive mechanism nozzle 3.

The investigation of the causative conditions surrounding the degradation of the reactor pressure vessel head at Davis-Besse is continuing. Boric acid or other contaminants could be contributing factors, as could steam jet cutting caused by leakage from the nozzle. Other factors contributing to the degradation might include the environment (e.g., wet/dry) surrounding the reactor pressure vessel head during both operating and shutdown conditions, the duration for which the reactor pressure vessel head was exposed to boric acid, and the source of the boric acid (e.g., leakage from cracks in the reactor pressure vessel head penetration nozzle or from sources above the reactor pressure vessel head such as control rod drive mechanism flanges).

Discussion

The reactor pressure vessel head is an integral part of the reactor coolant pressure boundary, and its integrity is important to the safe operation of the plant. The recent identification of thinning of the reactor pressure vessel head at Davis-Besse raises questions regarding licensees' practices for identifying and resolving degradation of the reactor coolant pressure boundary, including licensees' models for assessing corrosion that is caused by contaminants such as boric acid in the operating environment of the reactor pressure vessel head, or erosion that is caused by flow through a through-wall defect in a vessel head penetration nozzle.

As indicated above, the investigation of the causative conditions surrounding the degradation of the reactor pressure vessel head at Davis-Besse is continuing. An evaluation of the available information leads to several observations. First, the base metal of the reactor pressure vessel head degraded near leaking nozzles. Second, the reactor pressure vessel head has had boric acid deposits in the vicinity of the degraded areas for at least the past several years; that is, the deposits were not fully removed during the last several refueling outages. Third, some of the boric acid deposits on the top of the reactor pressure vessel head came from leaking control rod drive mechanism flanges, as discussed in NRC Information Notice 2002-11. Evaluations are on-going on whether similar degradation could occur (1) with just deposits and/or contaminants on the reactor pressure vessel head (i.e., without a leaking nozzle), (2) with just a leaking nozzle (i.e., without deposits and/or contaminants on the reactor pressure vessel head), or (3) whether both conditions are necessary to cause the observed degree of degradation. That is, the interaction between these two conditions and their respective influences in initiating the degradation of the reactor pressure vessel head is still being evaluated.

Although the root cause is still under investigation, preliminary assessments indicate that boric acid was a contributor. Corrosion of ferritic material, such as the base metal of the reactor pressure vessel head, is well documented in the list of related generic communications identified in this bulletin. In response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," dated March 17, 1988, licensees committed to implement a systematic program to monitor locations where boric acid leakage could occur, and to implement measures to prevent degradation of the reactor coolant pressure boundary by boric acid corrosion.

Historically, these programs have assumed that there is only a small potential for wastage of the reactor pressure vessel head attributable to leakage of primary coolant through the vessel head penetration nozzles. The supporting analyses assumed that coolant escaping from a penetration would flash to steam, leaving behind deposits of boric acid crystals. Typically, these crystals are assumed to accumulate on the reactor pressure vessel head; however, such deposits are assumed to cause minimal corrosion while the reactor is operating because the temperature of the reactor pressure vessel head is above 500 F during operation, and dry boric acid crystals are not very corrosive. Therefore, wastage is typically expected to occur only during outages when the boric acid could be in solution, such as when the temperature of the reactor pressure vessel head falls below 212 F. However, the findings at Davis-Besse bring into question the reliability of this model.

As indicated above, one of the contributing factors to the observed degradation could be the presence of boric acid deposits on the top of the reactor pressure vessel head. The procedures for determining whether these deposits could be present on the top of the reactor pressure vessel head are plant-specific because they are contingent on plant-specific design characteristics. For example, some plants have the reactor pressure vessel head insulation sufficiently offset from the head itself, in order to allow effective visual examination (as discussed in Bulletin 2001-01). Other plants have the insulation offset from the reactor pressure vessel head, but in a contour matching that of the head itself, in a design that requires special tooling and procedures to perform an effective visual examination. Still other plants have the reactor pressure vessel head insulation directly adjacent or attached to the head itself, in a design that potentially requires the removal of the insulation to permit an effective visual examination.

Plants for which limited data are available from direct visual inspection must use another method to determine whether boric acid deposits could be on the top of the reactor pressure vessel head. One method includes assessing whether boric acid (1) has leaked from locations above the reactor pressure vessel head, (2) has penetrated the insulation by flowing through the insulation or through gaps in the insulation, and (3) has precipitated onto the reactor pressure vessel head or has allowed precipitants to fall onto the reactor pressure vessel head.

One of the other factors suspected of contributing to the degradation observed at Davis-Besse is the presence of a leaking reactor pressure vessel head penetration nozzle. The integrity of reactor pressure vessel head penetration nozzles is discussed in NRC Bulletin 2001-01.

That bulletin discusses an industry model for assessing the susceptibility of plants to primary water stress corrosion cracking at the reactor pressure vessel head penetration nozzles. The industry's susceptibility ranking model has limitations, such as large uncertainties and the inability to predict when cracking will occur. Nonetheless, this model does provide a starting point for assessing the potential for cracking of reactor pressure vessel head penetration nozzles in pressurized water reactor plants.

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.

Several plants have repaired nozzles with through-wall degradation (i.e., nozzles that leaked). Results from these inspections do not appear to indicate the presence of a degraded area in the reactor pressure vessel base metal. However, the extent to which the inspection techniques used would have detected such an area or the degree to which attention was placed on identifying this form of degradation, varies from plant to plant. 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.

The NRC has developed Web pages to keep the public informed of generic activities related to Alloy 600 cracking and reactor pressure vessel head degradation:

> http://www.nrc.gov/reactors/operating/ops-experience/alloy600.html
> http://www.nrc.gov/reactors/operating/ops-experience/vessel-head-degradation.html

These Web pages provide links to information regarding the cracking identified to date, along with documentation of NRC interactions with industry (industry submittals, meeting notices, presentation materials, and meeting summaries). The NRC will continue to update these Web pages as new information becomes available.

<u>Applicable Regulatory Requirements</u>

Several provisions of the NRC regulations and plant operating licenses (Technical Specifications) pertain to reactor coolant pressure boundary integrity. The general design criteria (GDC) for nuclear power plants (Appendix A to 10 CFR Part 50), or, as appropriate, similar requirements in the licensing basis for a reactor facility, the requirements of 10 CFR 50.55a, and the quality assurance criteria of Appendix B to 10 CFR Part 50 provide the bases and requirements for NRC staff assessment of the potential for and consequences of degradation of the reactor coolant pressure boundary.

The applicable GDC include GDC 14 (Reactor Coolant Pressure Boundary), GDC 31 (Fracture Prevention of Reactor Coolant Pressure Boundary), and GDC 32 (Inspection of Reactor Coolant Pressure Boundary). GDC 14 specifies that the reactor coolant pressure boundary (RCPB) has an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture. GDC 31 specifies that the probability of rapidly propagating fracture of the RCPB be minimized. GDC 32 specifies that components which are part of the RCPB have the capability of being periodically inspected to assess their structural and leaktight integrity; inspection practices that do not permit reliable detection of degradation are not consistent with this GDC.

NRC regulations in 10 CFR 50.55a state that the American Society of Mechanical Engineers (ASME) Class 1 components (which includes the reactor coolant pressure boundary) must meet the requirements of Section XI of the ASME Boiler and Pressure Vessel Code. Various portions of the ASME Code address reactor coolant pressure boundary inspection. For example, Table IWA-2500-1 of Section XI of the ASME Code provides examination requirements for reactor pressure vessel head penetration nozzles and references IWB-3522 for acceptance standards. IWB-3522.1(c) and (d) specify that conditions requiring correction include the detection of leakage from insulated components and discoloration or accumulated residues on the surfaces of components, insulation, or floor areas which may reveal evidence of borated water leakage, with leakage defined as "the through-wall leakage that penetrates the pressure retaining membrane." Therefore, 10 CFR 50.55a, through its reference to the ASME Code, does not permit through-wall degradation of the reactor pressure vessel head penetration nozzles.

For through-wall leakage identified by visual examinations in accordance with the ASME Code, acceptance standards for the identified degradation are provided in IWB-3142. Specifically, supplemental examination (by surface or volumetric examination), corrective measures or repairs, analytical evaluation, and replacement provide methods for determining the acceptability of degraded components.

Criterion V (Instructions, Procedures, and Drawings) of Appendix B to 10 CFR Part 50 states that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Criterion V further states that instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Visual and volumetric examinations of the reactor coolant pressure boundary are activities that should be documented in accordance with these requirements.

Criterion IX (Control of Special Processes) of Appendix B to 10 CFR Part 50 states that special processes, including nondestructive testing, shall be controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements. Within the context of providing assurance of the structural integrity of reactor coolant pressure boundary for the degradation observed at Davis-Besse, special requirements for visual examination and/or ultrasonic testing would generally require the use of qualified visual and ultrasonic testing methods. Such methods are ones that a plant-specific analysis has demonstrated would result in the reliable detection of degradation prior to a loss of specified reactor coolant pressure boundary margins of safety. The analysis would have to consider, for example, the as-built configuration of the system and the capability to reliably detect and accurately characterize flaws or degradation, and contributing factors such as the presence of insulation, preexisting deposits, and other factors that could interfere with the detection of degradation.

Criterion XVI (Corrective Action) of Appendix B to 10 CFR Part 50 states that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. For significant conditions adverse to quality, the measures taken shall include root cause determination and corrective action to preclude repetition of the adverse conditions. For degradation of the reactor coolant pressure boundary, the root cause determination is important for understanding the nature of the degradation present and the required actions to mitigate future degradation. These actions could include proactive inspections and repair of degraded portions of the reactor coolant pressure boundary.

Plant technical specifications pertain to this issue insofar as they do not allow operation with known reactor coolant system pressure boundary leakage.

Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," pertains to this issue in that the staff concluded that in the absence of a program for addressing the corrosive effects of reactor coolant system leakage, compliance with General Design Criteria 14, 30, and 31 cannot be ensured.

<u>Required Information</u>

1. Within 15 days of the date of this 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 your plant,

   B. an evaluation of the ability of your inspection and maintenance programs to identify degradation of the reactor pressure vessel head including, thinning, pitting, or other forms of degradation such as the degradation of the reactor pressure vessel head observed at Davis-Besse,

   C. a description of any conditions identified (chemical deposits, head degradation) through the inspection and maintenance programs described in 1.A that could have led to degradation and the corrective actions taken to address such conditions,

   D. your schedule, plans, and basis for future inspections of the reactor pressure vessel head and penetration nozzles. This should include the inspection method(s), scope, frequency, qualification requirements, and acceptance criteria, and

   E. your conclusion regarding whether there is reasonable assurance that regulatory requirements are currently being met (see the Applicable Regulatory Requirements, above). This discussion should also explain your basis for concluding that the inspections discussed in response to Item 1.D will provide reasonable assurance that these regulatory requirements will continue to be met. Include the following specific information in this discussion:

(1) If your evaluation does not support the conclusion that there is reasonable assurance that regulatory requirements are being met, discuss your plans for plant shutdown and inspection.

(2) If your evaluation supports the conclusion that there is reasonable assurance that regulatory requirements are being met, provide your basis for concluding that all regulatory requirements discussed in the Applicable Regulatory Requirements section will continue to be met until the inspections are performed.

2. Within 30 days after plant restart following the next inspection of the reactor pressure vessel head to identify any degradation, all PWR addressees are required to submit to the NRC the following information:

   A. the inspection scope (if different than that provided in response to Item 1.D.) and results, including the location, size, and nature of any degradation detected,

   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 your 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.

The information required in Item 1.A, 1.B, and 1.C, should address:

- the material condition of the reactor pressure vessel head as determined through direct visual examinations dating back to the last time the entire reactor pressure vessel head was visually inspected to the bare metal. Include the date of the last 100 percent bare metal inspection, the results of that examination, and the extent and results of visual examinations conducted since the last 100 percent bare metal inspection. If no 100 percent bare metal inspection has ever been conducted, indicate so in your response.

- any leaks of boric acid or any other corrosive material onto the reactor pressure vessel head or insulation since the last 100 percent bare metal inspection (the results of which were provided in responding to 1.C). Include the extent to which boric acid deposits or other corrosive materials were removed from the reactor pressure vessel head, the length of time this material was left on the reactor pressure vessel head (and whether it is still on the reactor pressure vessel head), and the condition of the head following removal of the deposits. Also include a discussion of your program for preventing corrosion of the reactor pressure vessel head and the location of the leaks relative to any nozzle with through-wall cracks. If leakage was onto the insulation, discuss whether the leakage could have permeated the insulation or flowed through gaps in the insulation (e.g., around nozzles) such that deposits accumulated on the reactor pressure vessel head.

- the leakage integrity of the reactor pressure vessel head penetration nozzles. Include a summary of inspections performed (including scope and extent) to detect cracking and/or degradation of the vessel penetration weld or nozzle base metal, whether the inspection plan included any examination that could identify a potential cavity behind the reactor pressure vessel head nozzle, and if so, the potential for the inspection method used to accurately and reliably detect a cavity in the reactor pressure vessel head near the penetration nozzles (including the basis for this conclusion), particularly in cases where a leakage path has existed (i.e., even if the nozzle has been repaired). For repaired nozzles, the description should include the scope and results from the post-repair inspections.

Required Response

In accordance with 10 CFR 50.54(f), in order to determine whether any license should be modified, suspended, or revoked, each PWR addressee is required to respond as described below. This information is sought to verify licensee compliance with the current licensing basis for the facilities covered by this bulletin.

Within 7 days of the date of this bulletin, a PWR addressee is required to submit a written response if they are unable to provide the information or they can not meet the requested completion dates. The PWR addressee must address in their response any alternative course of action they propose to take, including the basis for the acceptability of the proposed alternative course of action.

The required written response should be addressed to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, 11555 Rockville Pike, Rockville, MD 20852, under oath or affirmation under the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50. 54(f). In addition, submit a copy of the response to the appropriate regional administrator.

Reasons for Information Request

Extensive degradation of the reactor coolant pressure boundary including leakage violates NRC regulations and plant technical specifications. Degradation of the reactor pressure vessel head or other portions of the reactor coolant pressure boundary can pose a significant safety risk if permitted to progress to the point that their integrity is in question and the risk of a loss of coolant accident increases. This information request is necessary to permit the assessment of plant-specific compliance with NRC regulations. This information will also be used by the NRC staff to determine the need for, and to guide the development of, additional regulatory actions to address degradation of the reactor pressure vessel head and/or other portions of the reactor coolant pressure boundary. Such regulatory actions could include regulatory requirements for augmented inspection programs under 10 CFR 50.55a(g)(6)(ii) or additional generic communication.

The NRC staff is interacting with the industry on the implications of the degradation observed at Davis-Besse. The NRC staff will continue to assess additional information it receives on this subject in determining the need for, and to guide the development of, additional regulatory actions to address degradation of the reactor pressure vessel head and/or other portions of the reactor coolant pressure boundary.

Related Generic Communications

- Information Notice 2002-11: "Recent Experience with Degradation of Reactor Pressure Vessel Head," March 12, 2002. [ADAMS Accession No. ML020700556]
- Bulletin 2001-01: "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," August 3, 2001. [ADAMS Accession No. ML012080284]
- Information Notice 2001-05, "Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3," April 30, 2001. [ADAMS Accession No. ML011160588]
- Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," April 1, 1997.
- Information Notice 96-11, "Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations," February 14, 1996.
- Information Notice 86-108, Supplement 3, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," January 5, 1995.
- NUREG/CR-6245, "Assessment of Pressurized Water Reactor Control Rod Drive Mechanism Nozzle Cracking," October 1994.
- Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks," August 30, 1994.
- Information Notice 90-10, "Primary Water Stress Corrosion Cracking of INCONEL 600," February 23, 1990.
- Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," March 17, 1988.
- Information Notice 86-108, Supplement 2, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," November 19, 1987.
- Information Notice 86-108, Supplement 1, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," April 20, 1987.
- Information Notice 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," December 29, 1986.

- Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants," June 2, 1982.
- Information Notice 82-06, "Failure of Steam Generator Primary Side Manway Closure Studs," March 12, 1982.
- Information Notice 80-27, "Degradation of Reactor Coolant Pump Studs," June 11, 1980.

Backfit Discussion

Under the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f), this bulletin transmits an information request for the purpose of verifying compliance with existing applicable regulatory requirements (see the Applicable Regulatory Requirements section of this bulletin). Specifically, the required information will enable the NRC staff to determine whether current inspection and maintenance practices for the detection of degradation of the reactor coolant pressure boundary at reactor facilities (similar to that observed at Davis-Besse) provides reasonable assurance that reactor coolant pressure boundary integrity is being maintained. The required information will also enable the NRC staff to determine whether PWR addressee inspection and maintenance practices need to be augmented to ensure that the safety significance of this form of degradation remains low. No backfit is either intended or approved by the issuance of this bulletin, and the staff has not performed a backfit analysis.

Federal Register Notification

A notice of opportunity for public comment on this bulletin was not published in the *Federal Register* because the NRC staff is requesting information from power reactor licensees on an expedited basis for the purpose of assessing compliance with existing applicable regulatory requirements and the need for subsequent regulatory action. This bulletin was prompted by the discovery of degradation of the reactor pressure vessel head at Davis-Besse. Degradation of this extent has not been postulated or identified in PWRs. As the resolution of this matter progresses, the opportunity for public involvement will be provided.

Small Business Regulatory Enforcement Fairness Act

The NRC has determined that this action is not subject to the Small Business Regulatory enforcement Fairness Act of 1996.

Paperwork Reduction Act Statement

This bulletin contains an information collection that is subject to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.). This information collection was approved by the Office of Management and Budget, clearance number 3150-0012, which expires July 31, 2003. The burden to the public for this mandatory information collection is estimated to average 135 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the information collection. Send comments regarding this burden estimate or any other aspect of this information collection, including suggestions for reducing the burden, to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by Internet electronic mail at INFOCOLLECTS@NRC.GOV; and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202, (3150-0012), Office of Management and Budget, Washington, DC 20503.

Public Protection Notification

If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

If you have any questions about this matter, please contact one of the persons listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

/ RA /

David B. Matthews, Director
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

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Lead Project Manager: Steven D. Bloom, NRR
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Reference H

Pressurized Water Reactors in the United States

Unit	Reactor Design	Reactor Vessel Head Fabricator
Arkansas Nuclear 1	Babcock and Wilcox	Babcock and Wilcox
Arkansas Nuclear 2	Combustion Engineering	Combustion Engineering
Braidwood 1	Westinghouse	Babcock and Wilcox
Braidwood 2	Westinghouse	Babcock and Wilcox
Byron 1	Westinghouse	Babcock and Wilcox
Byron 2	Westinghouse	Babcock and Wilcox
Callaway	Westinghouse	Combustion Engineering
Calvert Cliffs 1	Combustion Engineering	Combustion Engineering
Calvert Cliffs 2	Combustion Engineering	Combustion Engineering
Catawba 1	Westinghouse	Rotterdam Dockyard
Catawba 2	Westinghouse	Combustion Engineering
Comanche Peak 1	Westinghouse	Combustion Engineering
Comanche Peak 2	Westinghouse	Combustion Engineering
Crystal River 3	Babcock and Wilcox	Babcock and Wilcox
Davis-Besse	Babcock and Wilcox	Babcock and Wilcox
D.C. Cook 1	Westinghouse	Combustion Engineering
D.C. Cook 2	Westinghouse	Chicago Bridge & Iron
Diablo Canyon 1	Westinghouse	Combustion Engineering
Diablo Canyon 2	Westinghouse	Combustion Engineering
Fort Calhoun	Combustion Engineering	Combustion Engineering
Ginna	Westinghouse	Babcock and Wilcox
H.B. Robinson 2	Westinghouse	Combustion Engineering
Indian Point 2	Westinghouse	Combustion Engineering
Indian Point 3	Westinghouse	Combustion Engineering
Joseph M. Farley 1	Westinghouse	Babcock and Wilcox and Combustion Engineering
Joseph M. Farley 2	Westinghouse	Babcock and Wilcox and Combustion Engineering
Kewaunee	Westinghouse	Babcock and Wilcox and Combustion Engineering
McGuire 1	Westinghouse	Combustion Engineering
McGuire 2	Westinghouse	Rotterdam Dockyard
Millstone 2	Combustion Engineering	Combustion Engineering
Millstone 3	Westinghouse	Combustion Engineering
North Anna 1	Westinghouse	Rotterdam Dockyard
North Anna 2	Westinghouse	Rotterdam Dockyard
Oconee 1	Babcock and Wilcox	Babcock and Wilcox
Oconee 2	Babcock and Wilcox	Babcock and Wilcox
Oconee 3	Babcock and Wilcox	Babcock and Wilcox
Palisades	Combustion Engineering	Combustion Engineering
Palo Verde 1	Combustion Engineering	Combustion Engineering
Palo Verde 2	Combustion Engineering	Combustion Engineering
Palo Verde 3	Combustion Engineering	Combustion Engineering
Point Beach 1	Westinghouse	Babcock and Wilcox and Combustion Engineering
Point Beach 2	Westinghouse	Babcock and Wilcox
Salem 1	Westinghouse	Combustion Engineering
Salem 2	Westinghouse	Combustion Engineering
San Onofre 2	Combustion Engineering	Combustion Engineering
San Onofre 3	Combustion Engineering	Combustion Engineering
Seabrook 1	Westinghouse	Combustion Engineering
Sequoyah 1	Westinghouse	Rotterdam Dockyard

Unit	Reactor Design	Reactor Vessel Head Fabricator
Sequoyah 2	Westinghouse	Rotterdam Dockyard
South Texas Project 1	Westinghouse	Combustion Engineering
South Texas Project 2	Westinghouse	Combustion Engineering
St. Lucie 1	Combustion Engineering	Combustion Engineering
St. Lucie 2	Combustion Engineering	Combustion Engineering
Summer	Westinghouse	Chicago Bridge & Iron
Surry 1	Westinghouse	Babcock and Wilcox and Rotterdam
Surry 2	Westinghouse	Babcock and Wilcox and Rotterdam
Three Mile Island 1	Babcock and Wilcox	Babcock and Wilcox
Turkey Point 3	Westinghouse	Babcock and Wilcox
Turkey Point 4	Westinghouse	Babcock and Wilcox
Vogtle 1	Westinghouse	Combustion Engineering
Vogtle 2	Westinghouse	Combustion Engineering
Waterford 3	Combustion Engineering	Combustion Engineering
Watts Bar 1	Westinghouse	Rotterdam Dockyard
Wolf Creek	Westinghouse	Combustion Engineering

Reference I

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, DC 20555-0001

April 4, 2002

NRC INFORMATION NOTICE 2002-13: POSSIBLE INDICATORS OF ONGOING REACTOR PRESSURE VESSEL HEAD DEGRADATION

ADDRESSEES

All holders of operating licenses for pressurized water nuclear power reactors, except those who have permanently ceased operations and certified that fuel has been permanently removed from the reactor.

PURPOSE

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice on recent Davis-Besse experience to alert addressees to possible indicators of reactor coolant pressure boundary degradation including degradation of the reactor pressure vessel (RPV) head material. The NRC anticipates that recipients will review this information for applicability to their facilities and consider taking appropriate actions. However, the suggestions contained in this information notice do not constitute NRC requirements and, therefore, no specific action or written response is required.

DESCRIPTION OF CIRCUMSTANCES

The Davis-Besse nuclear power plant recently discovered a significant cavity in the RPV head on the downhill side of control rod drive nozzle number 3 and some head wastage behind nozzle number 2. In response, the NRC issued Information Notice 2002-11, "Recent Experience With Degradation of Reactor Pressure Vessel Head," on March 12, 2002, and Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," on March 18, 2002. NRC also sent an Augmented Inspection Team (AIT) to the plant to investigate the circumstances of the degradation of the RPV head material. Through the AIT, several possible indicators of reactor coolant pressure boundary degradation such as was observed at Davis-Besse were identified. These indicators include unidentified reactor coolant system (RCS) leakage and containment air cooler (CAC) and radiation element (RE) filter fouling.

Until 1998, RCS unidentified leakage at Davis-Besse was normally less than 0.1 gallons per minute (gpm). In October 1998, the licensee removed the rupture disks downstream of the pressurizer relief valves and bypassed a drain line that collected leakage from the relief valves in the quench tank (identified leakage). As a result, all leakage past the relief valves was vented directly into the containment atmosphere and collected in the sump, increasing the unidentified leakage to approximately 0.8 gpm. In May 1999, the licensee reinstalled the rupture disks and reconnected the drain line; however, the RCS unidentified leakage was only reduced to approximately 0.2 gpm (or approximately 0.1 gpm higher than normal). This elevated level of unidentified leakage was attributed by the licensee to control rod drive mechanism (CRDM) flange leakage since the plant had a past history of flange leakage.

The Davis-Besse CACs control containment temperature and humidity. In November 1998, the licensee identified increased CAC fouling caused by boron deposits. The licensee attributed the increase in CAC fouling to the venting of the pressurizer relief valve leakage directly to containment caused by the October 1998 modification discussed previously. The CACs were cleaned many times between November 1998 and May 1999. In May 1999, the licensee reinstalled the rupture disks and reconnected the drain line. After that modification, the licensee cleaned the CACs again in June and July 1999. At that time, the licensee noticed that the boric acid deposits removed from CAC number 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. After the spring 2000 refueling outage, deposits again began to form on the CACs. Between June 2000 and May 2001, the licensee cleaned the CACs eight times. No further CAC cleaning was needed until the current outage when the licensee reported that 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.

Davis-Besse also has REs that are two identical air sampling systems in containment. The RE 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 discussed previously. 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 this time, the licensee began changing the filters every one-to-three weeks. By November 1999, the frequency of filter changes had again increased.

DISCUSSION

RCS leakage, boron deposits, and corrosion products like ferric oxide in CACs and RE filters may indicate degradation of the reactor coolant pressure boundary materials. These indicators do not provide clear evidence of the degradation; however, they may provide an opportunity for licensees to suspect that degradation is ongoing. The NRC understands that the indications at Davis-Besse were sometimes complicated by other events (e.g., flange leaks). Nonetheless, in combination with other indicators, they may provide insights into whether degradation of the reactor coolant pressure boundary materials is occurring.

The information in this notice is, in part, based on preliminary information. The safety significance and generic implications of the information justify NRC's urgency to issue this information notice.

This information notice does not require any specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate project manager from the NRC's Office of Nuclear Reactor Regulation.

/RA/
William D. Beckner, Program Director
Operating Reactor Improvements Program
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Technical contacts: Ian Jung, NRR
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Attachment: List of Recently Issued NRC Information Notices

This information notice does not require any specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate project manager from the NRC's Office of Nuclear Reactor Regulation.

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Attachment: List of Recently Issued NRC Information Notices

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OFFICE	RSE	Tech Editor	BC:EMCB	(A)SC:RORP:DRIP	PD:RORP:DRIP
NAME	ICJung	PKleene*	WHBateman	TKoshy	WDBeckner
DATE	04/ /2002	04/04/2002	04/04/2002	04/04/2002	04/04/2002

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LIST OF RECENTLY ISSUED
NRC INFORMATION NOTICES

Information Notice No.	Subject	Date of Issuance	Issued to
99-28, Supp 1	Recall of Star Brand Fire Protection Sprinkler Heads	03/22/2002	All holders of licenses for nuclear power, research, and test reactors and fuel cycle facilities.
2002-12	Submerged Safety-Related Electrical Cables	03/21/2002	All holders of operating licenses or construction permits for nuclear power reactors
2002-11	Recent Experience with Degradation of Reactor Pressure Vessel Head	03/12/2002	All holders of operating licenses for pressurized-water reactors (PWRs), except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor.
2002-10	Nonconservative Water Level Setpoints on Steam Generators	03/07/2002	All holders of operating licenses for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor.
2002-09	Potential for Top Nozzle Separation and Dropping of Certain Type of Westinghouse Fuel Assembly	02/13/2002	All holders of operating licenses for nuclear power reactors, and non-power reactors and holders of licenses for permanently shutdown facilities with fuel onsite.
2002-08	Pump Shaft Damage Due to Excessive Hardness of Shaft Sleeve	01/30/2002	All holders of operating licenses for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor.

OL = Operating License
CP = Construction Permit

Reference J

006771.001780

NA702-01 R00

CONDITION REPORT

NO. 1999 - 1947

DESCRIPTION OF CONDITION:

An Area For Improvement (AFI) from the INPO evaluation identified that Equipment problems have complicated plant transients and have contributed to plant events.

☐ Continued

INITIATOR (print)	SIGNATURE	ORGANIZATION	PHONE NO.	MAIL STOP
Dave Eshelman	D. Eshelman	PE	8103	1056

REVIEW, INCLUDING ACTIONS TAKEN / RECOMMENDATIONS:

☐ NCAQ – RECOMMENDED ☒ N/A PLANT OPERATIONS ☐ Continued

SUPERVISOR (print)	SIGNATURE	ORGANIZATION	PHONE NO.	MAIL STOP	DATE
Dave Eshelman	D. Eshelman	PE	8103	1056	11/9/99

REPORTABILITY
☐ 1 HR ☐ 4 HR ☐ 24 HR ☐ N/A

OPERABLE
☐ YES ☐ NO ☐ NON TECH SPEC.

ACTIONS TAKEN / COMMENTS:

☐ Continued

SIGNATURE	DATE	TIME

CATEGORY	OWNER	DUE DATE	CAUSE DETERMINATION
Important	PE	12/10/99	Apparent Cause

☐ SRB ☐ ERB ☐ EXPERIENCE REVIEW ☒ CATPR ☐ EXTENT OF CONDITION ☐ POTENTIAL MRFF ☐ OTHER REVIEWS

NA702_01.DOT 12/98

cc: Initiator
KNowicki
NRM

[1780]

CONDITION REPORT | NO. 1999-1947 |

This CR was made important based on management determining this issue warranted apparent cause and CATPR.

MRC Administrator Krista Nowicki 11/10/99

Continued

006771.00178B

NA 702-02 R00

CONDITION REPORT

NO. 1999-1947 | Page 3 of 8

CAUSE/ACTIONS

Problem Statement

Equipment problems have complicated plant transients and have contributed to plant events.

Problem Analysis

Each individual event where equipment problems complicated plant transients/events had its own cause investigation and corrective actions as part of the CR/PCAQR process. In addition to the individual investigations, collective significance reviews were also performed.

PCAQR 1998-1904 performed a collective significance review of the 1998 events, event initiators, and material condition issues. In the area of equipment performance, the need to identify important equipment issues in the backlog and to align organizational priorities was identified. Remedial actions taken included; 1) reviewing the maintenance backlog work to ensure impact on equipment reliability was appropriately considered. (DSO-98-20055) 2) an assessment of equipment health to identify equipment concerns that were prudent to be performed during the remainder of Cycle 12 and during the mid-cycle outage. (NPE-99-00093) 3) a mid-cycle outage to address corrective work to improve plant reliability. 4) strengthening the boric acid control program.

Condition Report 1999-0646 superceded PCAQR 1998-1904. The equipment performance problems were reviewed for causal factors. Of the identified causes: 65% were equipment failure/degradation, 21% of the equipment performance problems were due to design configuration/analysis, and 14% of the problems were caused/contributed to by Maintenance/Testing. Further breakdown showed 28% of the failures were age related component failures, 14% of the failures were related to Preventive Maintenance Program weaknesses, and 25% of the equipment failures were due to human performance issues. The overall conclusion of CR 1999-0646 was that important equipment issues need to be identified and the organizational priorities aligned to address them. The HPES Causal Factor review identified the need to review equipment condition, age, preventive maintenance, and field work practices.

A broader look at the significant equipment problems was performed under Self-Assessment 1999-0076. The self-assessment included a review of all functional failures and Equipment Performance Information Exchange (EPIX) reportable events since January 1st, 1997. The population included 98 EPIX reports involving over 300 key components, sub-components and piece parts. This review was conducted using multiple slices looking for commonality. Data was collected from the INPO Web page on failures and events reported by other sites as well as the industry events data found in Significant Operating Events Reports and other sources to determine any application to failures experienced at Davis-Besse. Additionally data was collected on failures from sources such as the Department of Defense reliability database NPRD95.

☒ Continued

10 CFR PART 21? ☐ YES ☒ NO	SYSTEM CAPABLE OF PERFORMING SPECIFIED FUNCTION? ☐ YES ☐ NO ☒ N/A	
PREPARER (Print) A. C. McAllister	SIGNATURE [signature]	DATE 12/6/99
SUPERVISOR APPROVAL (Print) A. C. McAllister	SIGNATURE [signature]	DATE 12/6/99
MANAGER APPROVAL (Print) ☐ N/A DL Eshelman	SIGNATURE [signature]	DATE 12/8/99
SRB APPROVAL (Print) ☒ N/A	SIGNATURE	DATE
ERB APPROVAL (Print) ☒ N/A	SIGNATURE	DATE

NA702_02.DOT 12/98

The review determined that all of the common causes of the equipment problems had been properly addressed in the corrective action program. No new common causes were identified.

This self-assessment identified weaknesses in the current plant preventive maintenance program. Aging failure mechanisms were identified that the plant does not currently have any effective preventive or predictive activities to address. Condition Report 1999-1463 documented that the elastomers in diaphragm valves located in high radiation fields may fail earlier than normally expected. Condition Report 1999-1512 documented that additional monitoring capability is required to prevent the failure of large AC motors prior to the end of plant life. Project 1999-1016 was submitted to obtain budgetary funding to begin addressing equipment aging issues.

During the course of the aging review, investigators identified that we appear to have a knowledge deficiency with respect to component and material aging. An example to illustrate the lack of knowledge is the electrolytic capacitor aging problem. When the problem of electrolytic capacitors was first identified, an effort was made to identify all potential effected equipment. Personnel conducting the review of mechanical equipment often did not have sufficient technical knowledge to identify the potential problem and as a result, the electrical power and related control circuits associated with the mechanical equipment such as power supplies for components in mechanical systems were often overlooked. Additionally, some end of life failure mechanisms appear to have never been considered.

Typical Life spans of selected equipment were researched. It was identified that there is frequently a large variance in mean time between failures for most components. Review of Nonelectronic Parts Reliability Data 1995 (NPRD95) which is an U.S. Military database supports this conclusion as well as failure information from the petro chemical industry. A significant factor contributing to the difficulty in predicting the meantime between failures of components is the relatively small number of similar components both on site and within the nuclear power industry. Where a typical refinery might have 3000 similar pumps, we may have only four similar pumps on site, and within the industry only a few other sites use the same pump. Small numbers such as these make it difficult to obtain statistically significant results. When using data from other industries, caution must be exercised because many factors are involved in the rate of equipment aging. A number of these aging factors are operating environment, radiation exposure, energized state, run hours, number of demands, and the design and quality of initial construction, as well as quality of preventive maintenance. However, several valid observations on the equipment aging issue were made and are given below:

1) Mechanical components do not frequently fail catastrophically but rather exhibit some degradation before failure. The expected life of most mechanical equipment is relatively long. Most important pieces of mechanical equipment that have a life span less than 40 years have predictive activities that monitor the performance of the equipment. Few big "surprises" are expected for mechanical components. Examples of this include the turbines, large pumps, safety grade pumps, and a large number of motor operated or air operated valves.

2) Packing has an identified life of less than forty years and there were no identified activities to replace packing. As a result of this assessment, a plan has been developed to periodically repack valves in certain applications such as high-energy primary and secondary valves in containment, which can impact unidentified RCS leakage and or containment sump leakage. Reviews are still in progress to identify valves in steam and feedwater systems in containment that should be periodically repacked.

3) Many components have elastomers as sub components. The EQ program has identified many safety-related components with elastomer sub-components and PMs are in place to replace these before their identified end of life. It was recently identified that HP Feedwater Heater 1-4 and 2-4 Normal Drain Valve Positioners contain elastomers that are not intended to be used at the actual operating temperatures. Condition Report 1999-1731 was generated to track the resolution of this problem. Additionally it was identified that the elastomer in diaphragm valves located in high radiation fields may fail earlier than normally expected. Condition Report 1999-1463 was generated to ensure these diaphragm valves are evaluated and preventive maintenance activities are generated to resolve this potential problem.

☒ Continued

4) Electrical and electronic components often fail with little to no warning. Most of these components have life spans of less than forty years. It was also identified that many instrumentation vendors assume their equipment lifetime is in the 15 to 20 year range. Many Davis-Besse electronic systems have no programmatic refurbishment or replacement program such as the one instituted for the Integrated Control System (ICS). Resolution of this issue will be pursued under project 1999-1016.

5) Motors have an expected life which can vary from months to forty years, and as such it is unreasonable to expect all the important motors to last the life of the plant. A review of failure data from other plants via the Equipment Performance Information Exchange (EPIX) has 27 motor failures at various plants due to winding age problems in the last two years. Davis-Besse's recent winding failures have not been due to equipment age, but due to over-greasing or power cable problems. The Reactor Coolant Pump motors, Circ Water Pump Motors, and the Main Generator, as well as the EDGs had some activities to evaluate and /or refurbish these large electrical machines. A failure of one of these machines will have a significant negative economic consequence. A number of other motors on site which are important to plant reliability are not included in a refurbishment or predictive maintenance program. Examples of these motors include Condensate Pump motors, Turbine Plant Cooling Water Pump motors, Stator Cooling Water Pump motors, Component Cooling Water Pump motors, Makeup Pump motors, etc. Again a loss of one of these 4160 VAC motors could result in a significant economic loss. Resolution of this issue will be pursued under project 1999-1016 and Modification 99-61.

6) There are common misconceptions on site related to the plant's 40 year design life. During plant design, relatively few components were formally evaluated to determine their expected life. Only Class I systems received a fatigue analysis to verify the adequacy of components to operate for a forty year plant life. Some components such as the turbines, received some limited analysis, but this was only to identify the maximum time between inspections and was not intended to assess equipment lifetimes. Certain design specifications did specify a design life of 40 years in addition to typically referenced codes and standards. Some Specifications also identified some specific environmental conditions (ambient temperature and pressure and even cumulative radiation dose to the component over 40 years). Because the specifications do not normally identify all the conditions that could be correlated to service life, there was no mechanism to evaluate or certify this condition (other than the OEM's judgment). Additionally, vendors assume certain maintenance activities will be performed on the component during its life that we might take exception to such as repacking greased bearings every quarter.

Of the 98 EPIX reports and functional failures 18% of the time the root cause or the action to prevent reoccurrence was a preventive maintenance activity. The 4160 VAC breakers and the Auxiliary Boiler are typical examples of the preventive maintenance root cause or action to prevent reoccurrence. The inadequate preventive maintenance includes the lack of a PM, PM instructions not detailed enough, or PM frequency is not high enough. These specific causes were evenly distributed and a trend does not appear. It should be noted that there were two cases in which a plant power reduction was the result of inadequate preventive maintenance. In one case the cause was lack of details in the PM which resulted in improper reassembly. The second case was an oversight on the need for a preventive maintenance activity to clean control system fluid filters. Additionally there was one plant trip (Manual trip during SFRCS testing due to SP7B solenoid in October 1998) where a preventive maintenance activity to periodically replace the solenoids may have prevented the plant trip. These failures were addressed as common cause mechanisms and the corrective action is complete. It is impossible for any PM program to prevent all failures. Based upon a review of industry data submitted to EPIX, Davis-Besse percentage of failures due to inadequate preventive maintenance is within industry norms.

The self-assessment investigated the use of the INPO databases for assistance in failure investigation. This area of the assessment was investigated by the use of a questionnaire for the plant engineers. The various industry data bases were searched 68 times by those who responded. Reviews identified that some engineers conduct query the data bases more frequently than others with a range from 13 per year to as little as once per year. Additionally it was identified that the INPO EPIX failure database was queried only a few times. The survey also identified that the data base reviews have not identified any meaningful information. Meaningful data has been obtained in the past by others and the fact that no meaningful information was obtained by personnel performing the reviews is an indicator that reviews are not extracting information that is available. Improving the knowledge and capabilities of plant engineers to search the INPO EPIX failure database is being tracked as a follow-up item under SA 1999-0076.

☒ Continued

Industry Experience

INPO AP-913, Equipment Reliability Process Description, describes an integrated set of processes for maintaining equipment reliability. The document reflects the integration of experience gained from equipment performance assist visits to operating plants and benchmark trips to European and domestic utilities. The equipment reliability process was designed with the direct participation of several utilities actively involved in improvement and reengineering of their own processes.

In an effort to uncover the fundamental causes of our equipment reliability problems, the INPO equipment reliability process was compared to our existing process. Following are the significant differences. (Numbering reflects the INPO AP-913 step numbering.)

1.1 Establish Performance Criteria & Monitoring Parameters

Monitored parameters and acceptable levels of performance should be related to measurable indications of component degradation.

Component performance criteria include specific threshold values for condition-monitoring data.

1.3 Monitor/Trend Component Performance – Perform cross-system component failure and problem trending using maintenance history, condition report data, and industry operating experience such as EPIX.

Establish component engineering expertise to resolve emergent equipment and maintenance problems. This allows system engineers to perform longer term equipment reliability activities.

Suggested component engineering expertise: motors, pumps, valves(manual, check, relief, etc.), MOV, AOV, EQ, breakers, power supplies, recorders, controllers, transmitters, heat exchangers, with a focus beyond regulatory compliance for both short term and long term health.

Expand equipment failure trending for components used across several systems.

Trending of as-found equipment condition codes may provide early indication of potential failures or need to adjust PM task or frequency.

Consult non-nuclear sources of component failure information and trending parameters/strategies.

2.1 Perform Corrective Maintenance – Perform corrective maintenance in accordance with the station work management process. Ensure the as-found condition is documented for component type failure trending.

2.4 Key equipment Problems prioritization by Management – Establish a site-wide prioritization of equipment problems based on plant safety, operational impact, and station availability. This is a cross-discipline activity that should be performed by the key station leadership team. Equipment reliability improvement is the result of a common station focus to completely resolve key equipment problems.

Demonstrate a low tolerance for equipment problems.

Focus on the long term equipment reliability solutions, not just emergent failures.

Integrate this process with the site work management and corrective action processes.

Provide management support for the equipment reliability process with resources and budget.

☒ Continued

3. Does an Applicable PM Template Exist? – The PM template is a documented maintenance strategy for a particular component type that lists significant failure modes, possible indications of degradation, and recommended condition-based or time based PMs.

4.2 Develop System/Component Long Range Maintenance Strategy – Establish the optimal maintenance methods for each potential failure and define the long-term frequency for condition-based maintenance, planned refurbishment, and replacement. Long term strategy for component types such as MOVs and breakers should be included in each applicable system strategy for consistency.

Summary of weaknesses based on industry comparison

Lack of component engineers and associated component programs.

Lack of a method to record and trend as-found equipment condition.

Lack of an effective prioritization system.

Lack of dedicated equipment reliability resources.

Lack of PM templates.

Lack of system/component long-range maintenance strategies.

Lack of PM program focus.

Remedial Actions

Remedial actions for the specific events were covered under the individual PCAQRs/CRs.

1. Perform system health review to identify equipment problems and resolutions / schedule. Eshelman Complete
2. Review, reprioritize and reschedule equipment maintenance activities. Eshelman Complete
3. Review OEs, industry experience for components to identify vulnerabilities, and submit work items to preclude problems. Eshelman Complete
4. Revise Boric Acid Corrosion Control program based on benchmarking to schieve industry best practice. Eshelman Complete
5. Identify current equipment problems or concerns. Eshelman Complete
6. Compare 1998 problems and initiatives to current problems and initiatives to identify areas not covered. Eshelman 1/27/00
7. Address / prioritize the equipment / areas not covered. Eshelman 2/10/00
8. Identify any programmatic and/or organizational changes required to more aggressively deal with equipment issues. Eshelman / Rogers / Coakley 3/1/00
9. Develop and obtain agreement from site management on the goal of the PM program.(i.e. prevent all equipment failures, or prevent equipment failures which result in plant shutdowns, forced outages, etc.) Eshelman 3/1/00

☒ Continued

000771 - 003787

NA702-03 R00

	NO. 1999-1947	Page 8 of 8

Apparent Causes

1. Lack of component engineers and associated component programs which effectively apply industry experience. Much of the component expertise that existed on site 10 years ago was down sized and has not been replaced.
2. Lack of a method to record, retrieve, and trend as-found equipment condition. .
3. Lack of an effective site prioritization system.
4. Lack of dedicated equipment reliability resources.
5. Lack of standard PM templates to identify typical activities and frequencies for different groupings of equipment.
6. Lack of clear PM program goals.
6. Lack of system/component long-range maintenance strategies.

Corrective Action to Prevent Recurrence

1. Assignment and development of component engineers and the ability to trend components across system boundaries is being tracked under CR 1999-1948.

2. Work with PETP to update ED6665C, Personnel/Equipment History sheet to record as found condition. Shreiner Due Date 1/31/00

3. Creation of a site-wide prioritization system is being tracked under CR 1999-0646.

4. Provide at least one additional billet for equipment reliability. S. Moffit Due Date 12/25/99

5. Creation of component PM templates is being tracked under CR 1999-1948.

6. Develop long range maintenance strategies and goals. D. Eshelman Due Date 10/1/00

7. Implement any needed re-organizational changes to allow effective use of resources on long-term equipment issues and life-cycle engineering. D. Eshelman Due Date 7/30/00

☐ Continued

RECORD END SHEET

END
OF
RECORD

Reference K

NA 702-01 R00

CR 1999-1300

CONDITION REPORT	NO. 1999 - 1300	Page 1 of 17

DESCRIPTION OF CONDITION:

Several filters from the CTMT radiation monitors and a sample from the White Bird used for CTMT pressure releases were sent to Southwest Research Institute (SRI) for analysis as part of the RE4597AA/BA action plan. Per telecon with Dr. Richard Page of SRI, the analysis was completed on 7/29 with the following results:

The RE 4597BA filter from 7/3/99 contained primarily Iron Oxide (10-100 microns with some smaller particles down to 1 micron). There was also some measurable Chlorine. The Iron Oxide particles had a granular appeance indicating the source is from corrosion.

The RE 4597BA filter from 7/9/99 also had three darker spots on it which were analyzed to contain potassium and chlorine. A sample from the white bird filter also contained iron oxide. No Boron was detected, however, Dr. Page indicated there would have to be a large quantity of Boron on the filter to detect it. SRI will send a written report by next Friday.

☐ Continued

INITIATOR (print)	SIGNATURE	ORGANIZATION	PHONE NO.	MAIL STOP
Robert C. Hovland		SYSC	8406	1056

REVIEW, INCLUDING ACTIONS TAKEN / RECOMMENDATIONS:

TM 99-0022 has been initiated to reduce the iron oxide in the CTMT atmosphere per the RE4597AA/BA action plan. Followup activities are recommended to determine the source of the iron oxide.

☐ NCAQ – RECOMMENDED ☐ N/A PLANT OPERATIONS ☐ Continued

SUPERVISOR (print)	SIGNATURE	ORGANIZATION	PHONE NO.	MAIL STOP	DATE
Robert C. Hovland	for D.C. Gerson	SYSC	8406	1056	7/30/99

REPORTABILITY	OPERABLE
☐ 1 HR ☐ 4 HR ☐ 24 HR ☒ N/A	☒ YES ☐ NO ☐ NON TECH SPEC.

ACTIONS TAKEN / COMMENTS:

See actions taken above.

☐ Continued

SIGNATURE	DATE	TIME
TDM	7/30/99	1608

CATEGORY	OWNER	DUE DATE	CAUSE DETERMINATION
Important	SYSC	9/27/99	Apparent Cause

☐ SRB ☐ ERB	☐ EXPERIENCE REVIEW ☒ CATPR	☐ EXTENT OF CONDITION ☐ POTENTIAL MRFF	☐ OTHER REVIEWS

NA702_01.DOT 12/98

Initiator
K. Nowicki
[redacted]

[4275]

CONDITION REPORT	NO. 1999-1300	Page 2 of 17

Problem Statement::

The performance of the Containment Radiation Monitors, RE4597AA and RE4597BA has degraded due to repetitive low sample flow conditions. The cause of the low sample flow is due to a buildup of material on the particulate filters. The particulate matter is primarily an iron oxide powder but the source is unknown.

Apparent Cause:

A radiation monitor action plan was completed to check the RE4597AA/BA skid performance, inspect sample lines, check filter material, and analyze the particulate matter on the filters. The results indicate the low flow conditions are due to the particulate matter that is building up on the filters. The material was sent to Southwest Research Institute for analysis and was determined to be primarily an iron oxide (See attached report SwRI Project No. 18-2321-190). Some possible sources of the iron oxide include:

1. Containment Air Cooler activities during the mid-cycle outage including the CAC No. 1 motor replacement and decon activities.

2. CR 1999-0275 identified condensation on Service Water piping dripping onto and rusting the conduit below (585' above CACs)

While the exact source of the rust is not known, the high particulate problem developed about the same time as the Plant Startup (5/10/99) after the mid-cycle outage. The CAC motors were started on 5/4/99 and the Plant entered Mode 4 on 5/7/99 which required the alignment of CTMT Purge to the Mechanical Penetration Rooms. RE 4597AA had a low flow alarm on 5/10/99 and RE4597BA had a low flow alarm on 5/13/99. Subsequent filter changes were required every 24-48 hours.

Remedial Actions:

Temporary Modification 99-0022 installed four portable HEPA filtration units in containment on 8/10/99 per WO 99-005029-000 to reduce the particulate concentration.

The MRC assigned CATS Item #1 to SYSC to determine if an OE should be issued. SYSC will use the Nuclear Network to ask the industry if they have experienced a similar type of particulate problem. CATS Item #3

CATPR:

1. Plant Engineering will issue an Action Plan for 12RFO which will include CTMT walkdowns to identify possible sources and activities for rust removal CATS Item #2. PLANT ENGINEERING IS UTILIZING EXPERTS FROM SARGENT LUNDY TO REVIEW OUR ACTIONS FOR COMPLETENESS AND MAKE RECOMMENDATIONS. [signature] 9/29/99

☐ Continued

10 CFR PART 21? ☐ YES ☒ NO	SYSTEM CAPABLE OF PERFORMING SPECIFIED FUNCTION? ☒ YES ☐ NO ☐ N/A	
PREPARER (Print) Robert C. Hovland	SIGNATURE [signature]	DATE 9/23/99
SUPERVISOR APPROVAL (Print) David C. Geisen Supervisor-Electrical/Controls Systems	SIGNATURE [signature]	DATE 9/24/99
MANAGER APPROVAL (Print) ☐ N/A Dave Eshelman	SIGNATURE [signature]	DATE 9/27/99
SRB APPROVAL (Print) ☒ N/A	SIGNATURE	DATE
ERB APPROVAL (Print) ☒ N/A	SIGNATURE	DATE

CR1999-1300
Page 3 of 17

ANALYSIS OF FILTER DEPOSITS

Final Report
SwRI Project No. 18-2321-190

Prepared for

The Toledo Edison Company
Davis-Besse Plant
5501 North State Route 2
Oak Harbor, OH 43449

Prepared by

Richard A. Page

August 1999

SOUTHWEST RESEARCH INSTITUTE

[4277]

CR1999-1300
Page 4 of 17

ANALYSIS OF FILTER DEPOSITS

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Oak Harbor, OH 43449

Prepared by

Richard A. Page

August 1999

APPROVED

James Lankford, Jr., Director
Materials Engineering Department

An EDS spectrum from an overall area of deposit on filter 4597BA 7/9/99@2016, Figure 6, was essentially identical to those obtained from filter 4597BA 7/3/99@1400. Spectra were also obtained from two of the dark particles on the filter, Figures 7 and 8. These particles were different from the overall deposit in that the iron peaks were reduced and high potassium and chlorine peaks were present.

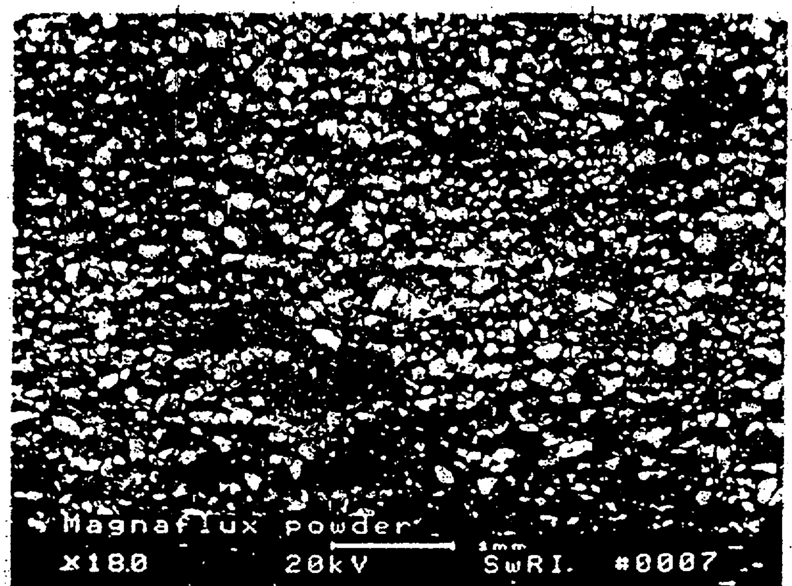
EDS spectra were also obtained from an overall area, Figure 9, and on an isolated particle Figure 10, on filter 7/16/99 White Bird. It is evident from these spectra that the deposits on the filter were also predominately iron oxide.

Imaging of the as-received filters in the SEM was limited by the low conductivity of the filter medium. To overcome this impediment, a gold palladium coating was applied to one of the filter samples, 4597BA 7/3/99@1400, following the EDS measurements. Electron micrographs obtained from the coated filter sample are shown in Figures 11 and 12. The deposits were generally less that 50μm in size and exhibited a very powdery appearance.

4.0 CONCLUSIONS

The following conclusions have been drawn from the results obtained in this investigation.

1. The uniform beige deposit that was present on the six 2¼ inch diameter filter samples was a powdery iron oxide. Small amounts of chlorine and copper were present in the deposit.
2. Large potassium chloride containing particles were present on one of the filters.
3. The deposits present on the 1¾ inch diameter filter were also primarily iron oxide.
4. Neither the shape nor the chemistry of the deposits is consistent with a Magnaflux powder origin. Titanium, a major constituent of the Magnaflux powder, was not detected on any of the filters examined, and the powdery morphology of the deposits was not at all similar to the larger angular Magnaflux powder.
5. The iron oxide deposits are likely corrosion products from an iron base component within the system.



97624 (a)

97625 (b)

Figure 1. Scanning electron micrographs of the Magnaflux powder.

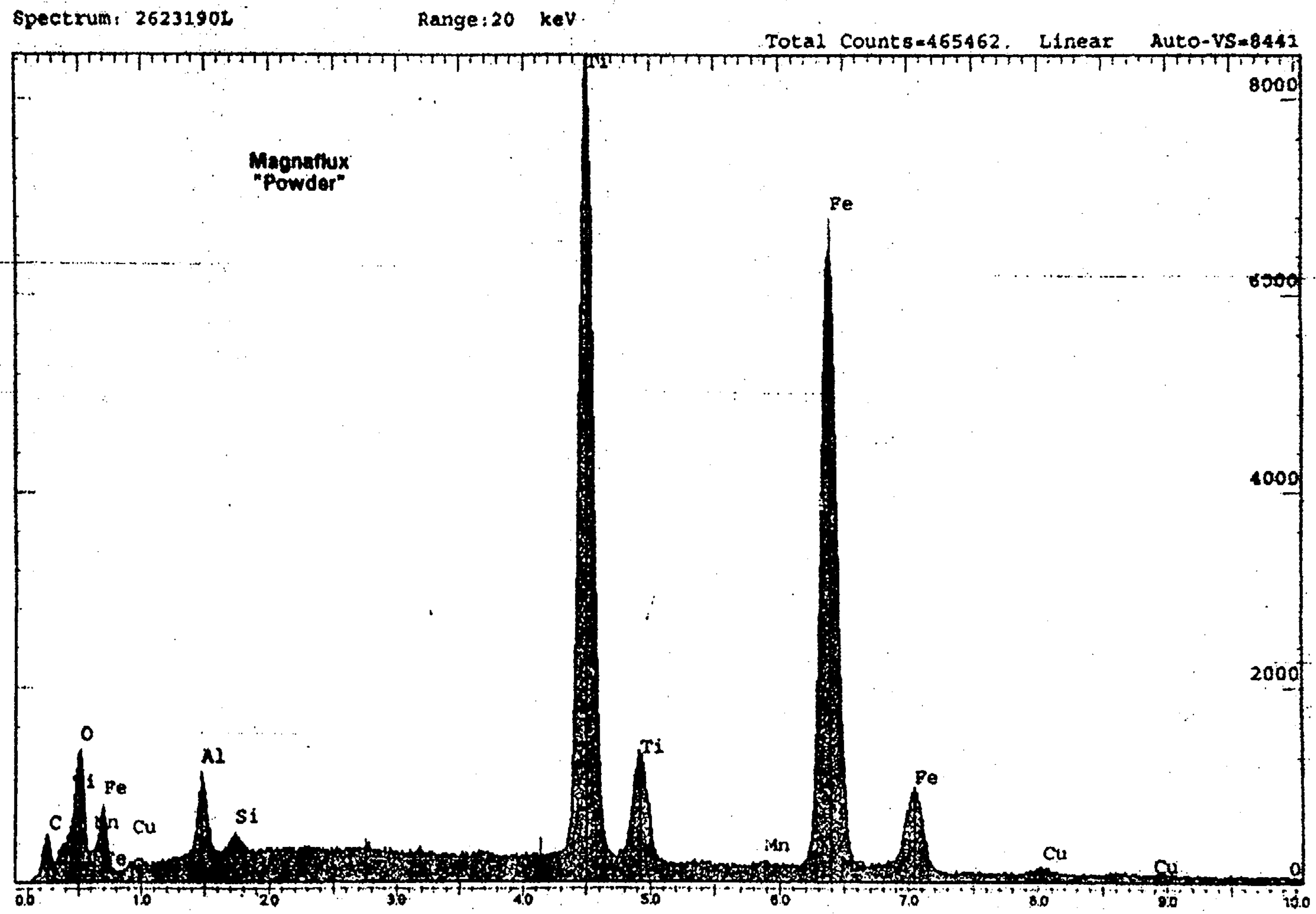


Figure 2. EDS spectrum obtained from the Magnaflux powder.

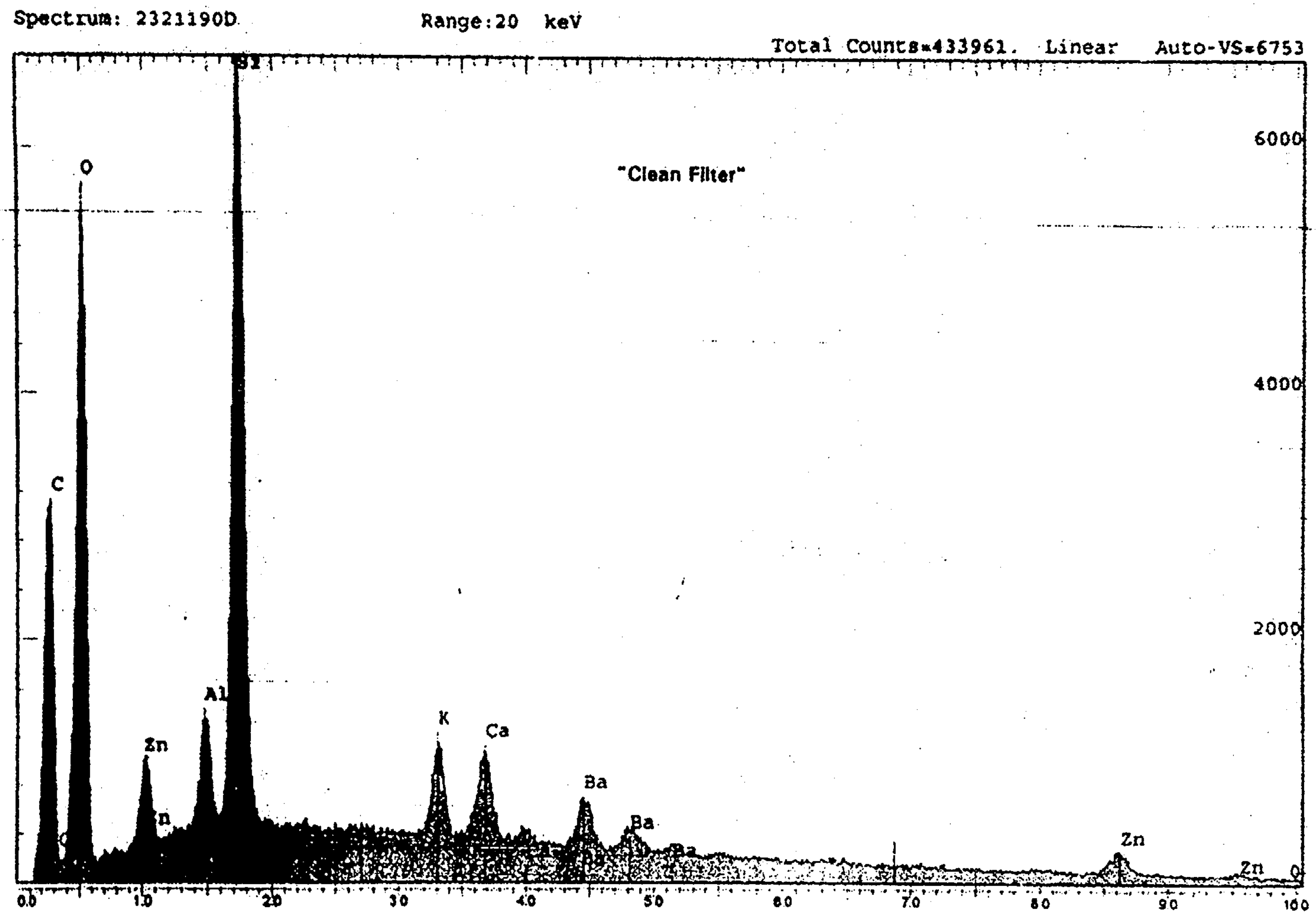


Figure 3. **EDS spectrum obtained from a deposit free section of filter 4597BA 7/9/99@1400.**

CR1999-1300
Page 8 of 17

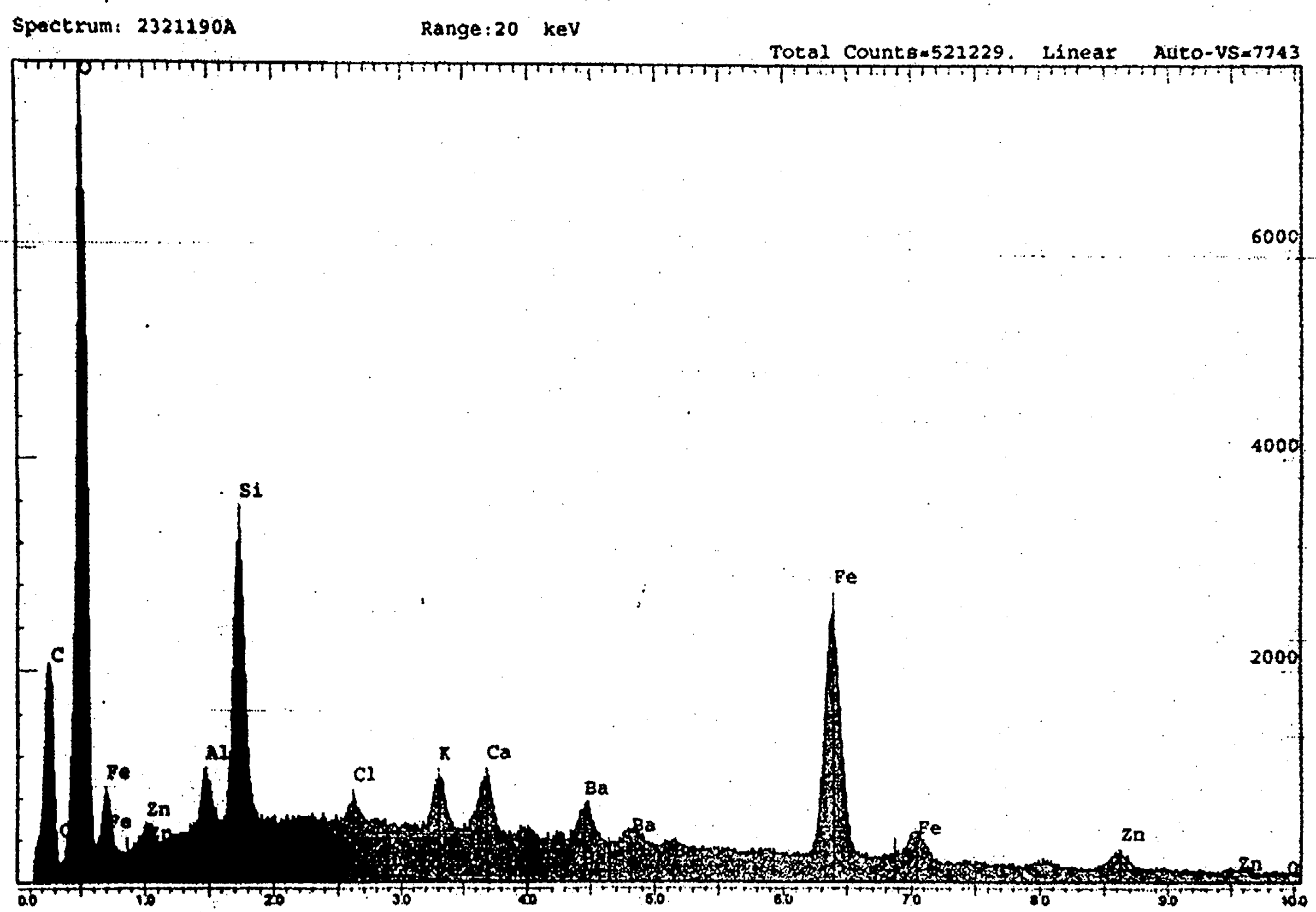


Figure 4. EDS spectrum from an overall area of deposits on filter 4597BA 7/3/99@1400.

CR1000/1800

Page 9 of 17

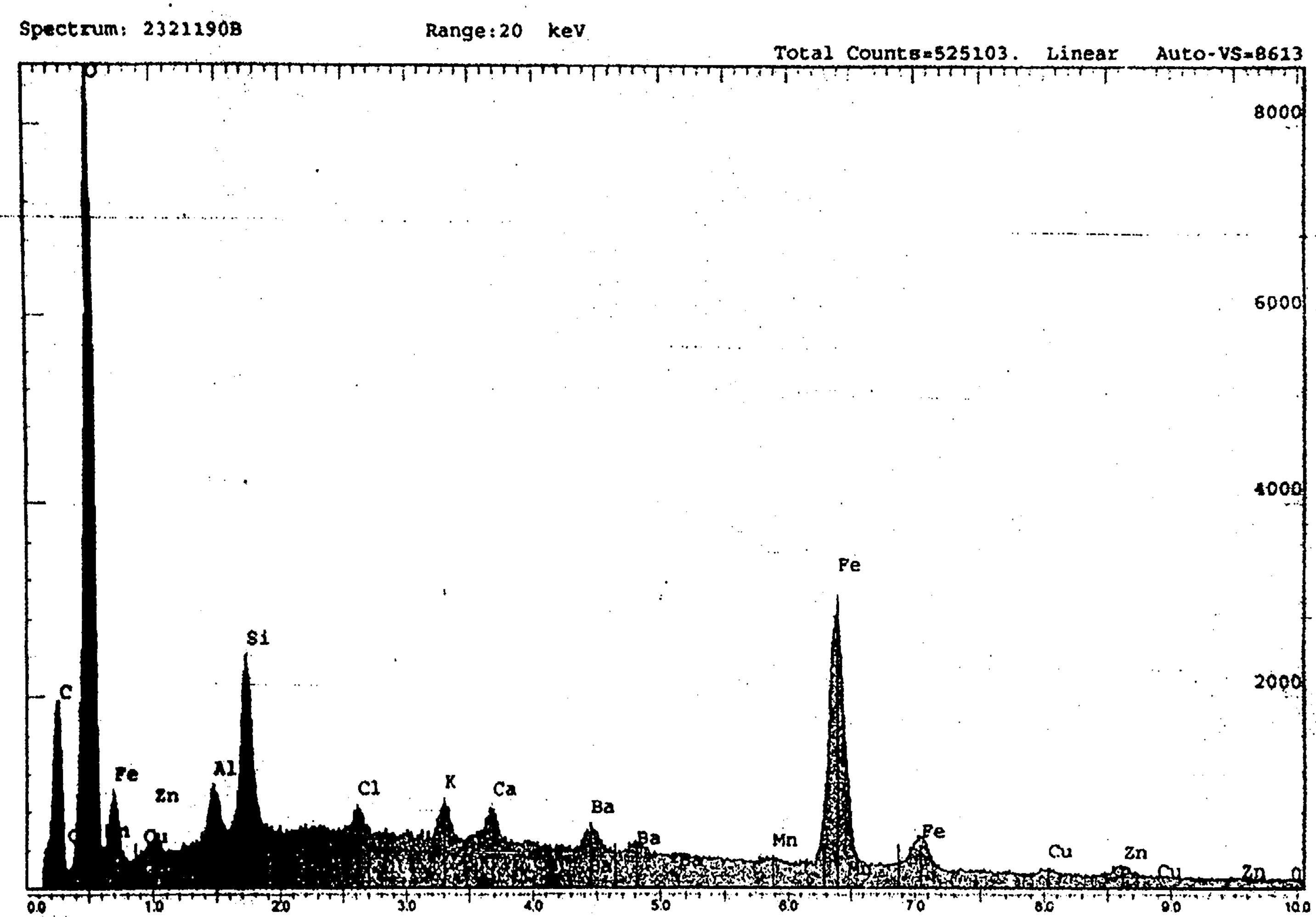


Figure 5. EDS spectrum from a second overall area of deposits on filter 4597BA 7/3/99@1400.

Page 10 of 17

[4283]

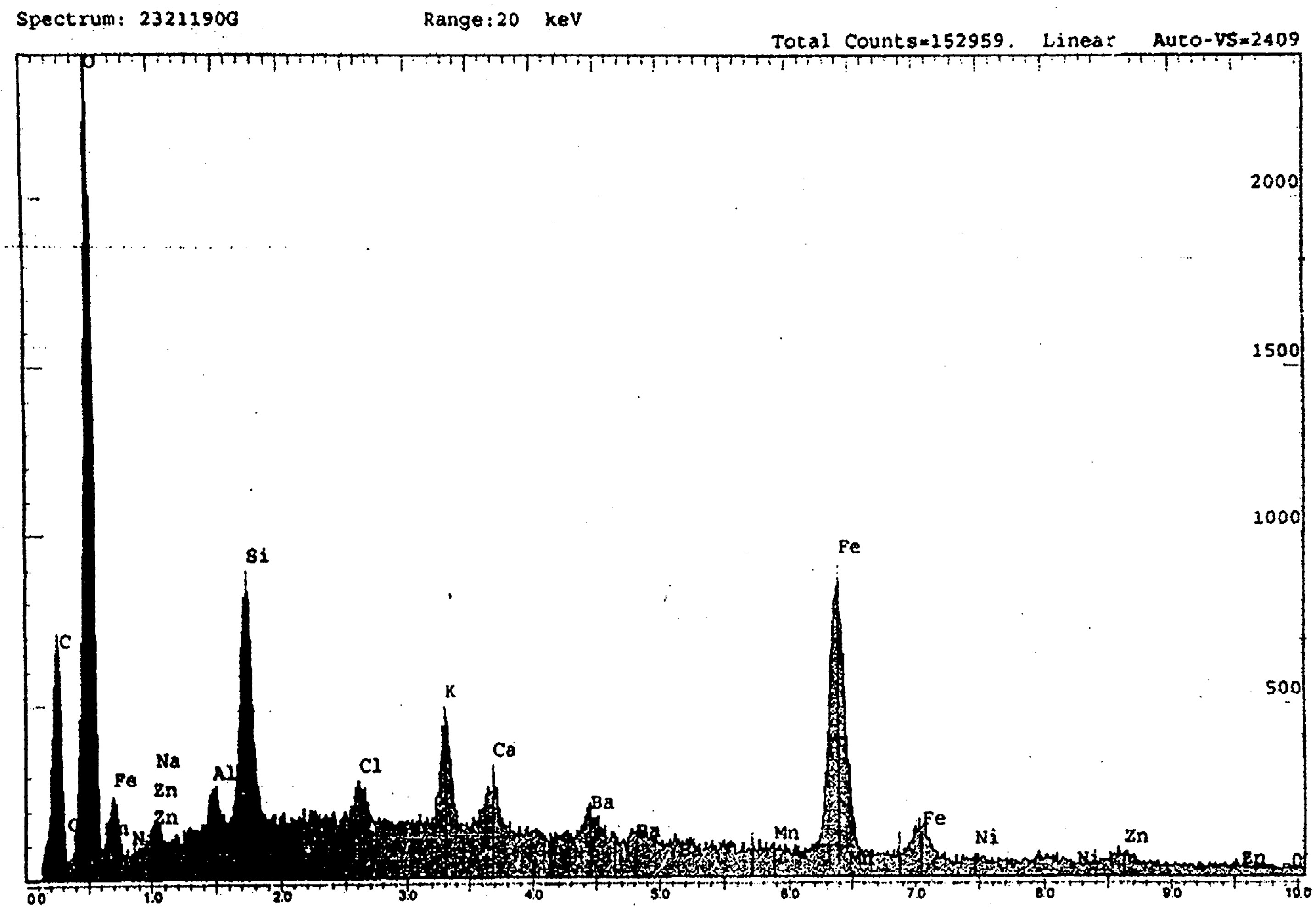


Figure 6. **EDS spectrum from an overall area of deposits on filter 4597BA 7/9/99@2016.**

CR1999-1300
Page 11 of 17

[4284]

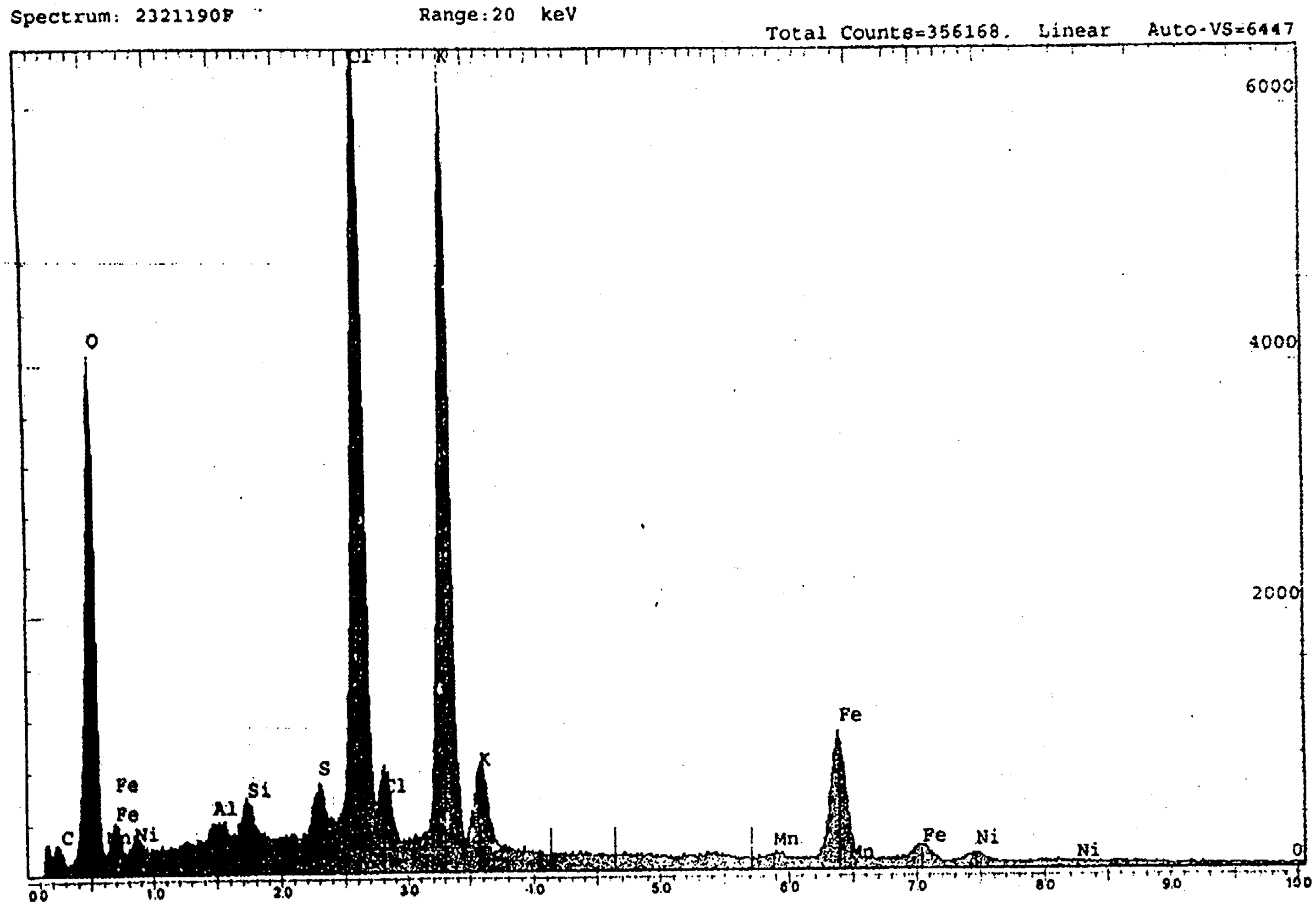


Figure 7. **EDS spectrum from a single dark particle on filter 4597BA 7/9/99@2016.**

Page 13 of 17

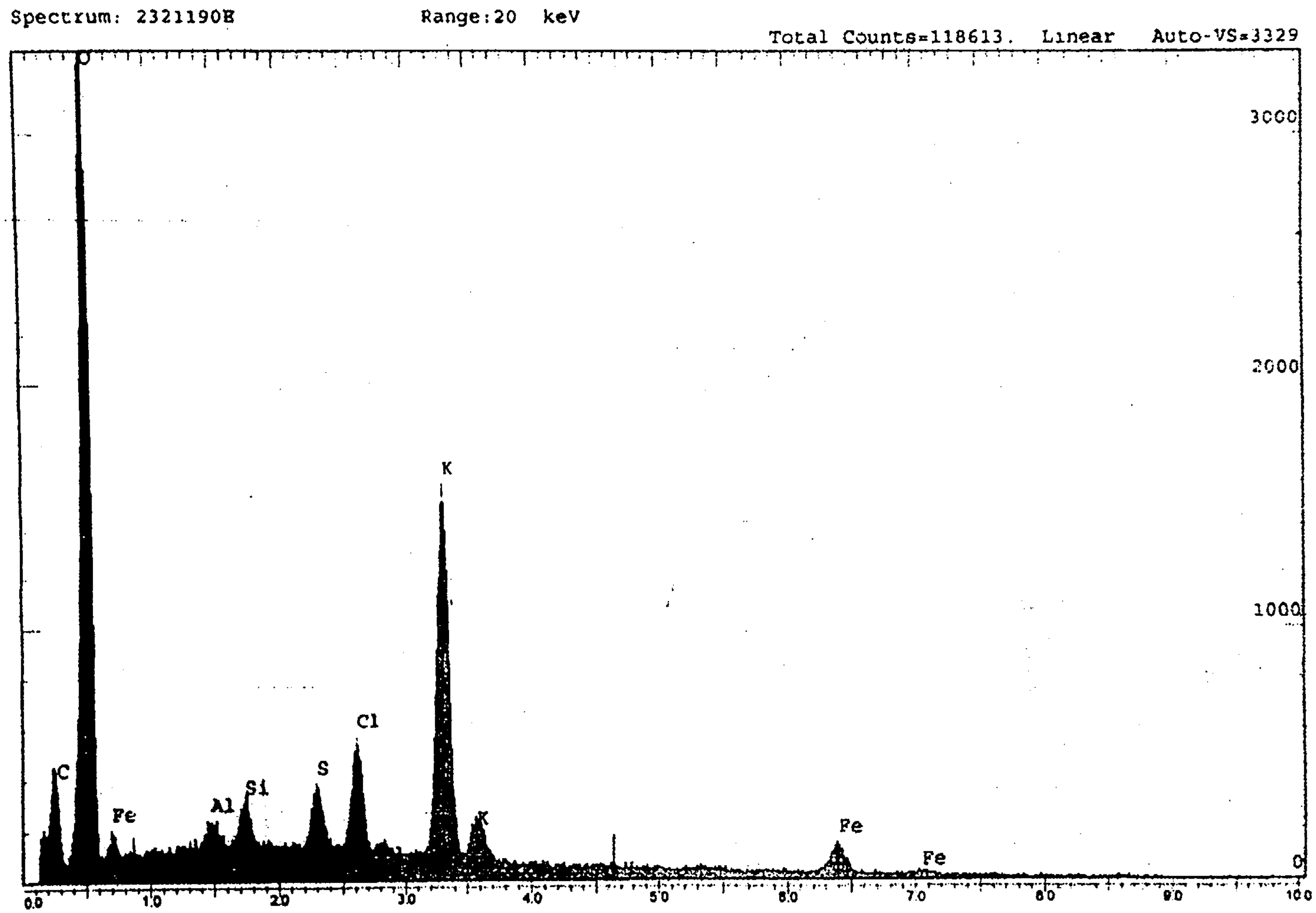


Figure 8. EDS spectrum from a second dark particle on filter 4597BA 7/9/99@2016.

GR 1999-1500
Page 13 of 17

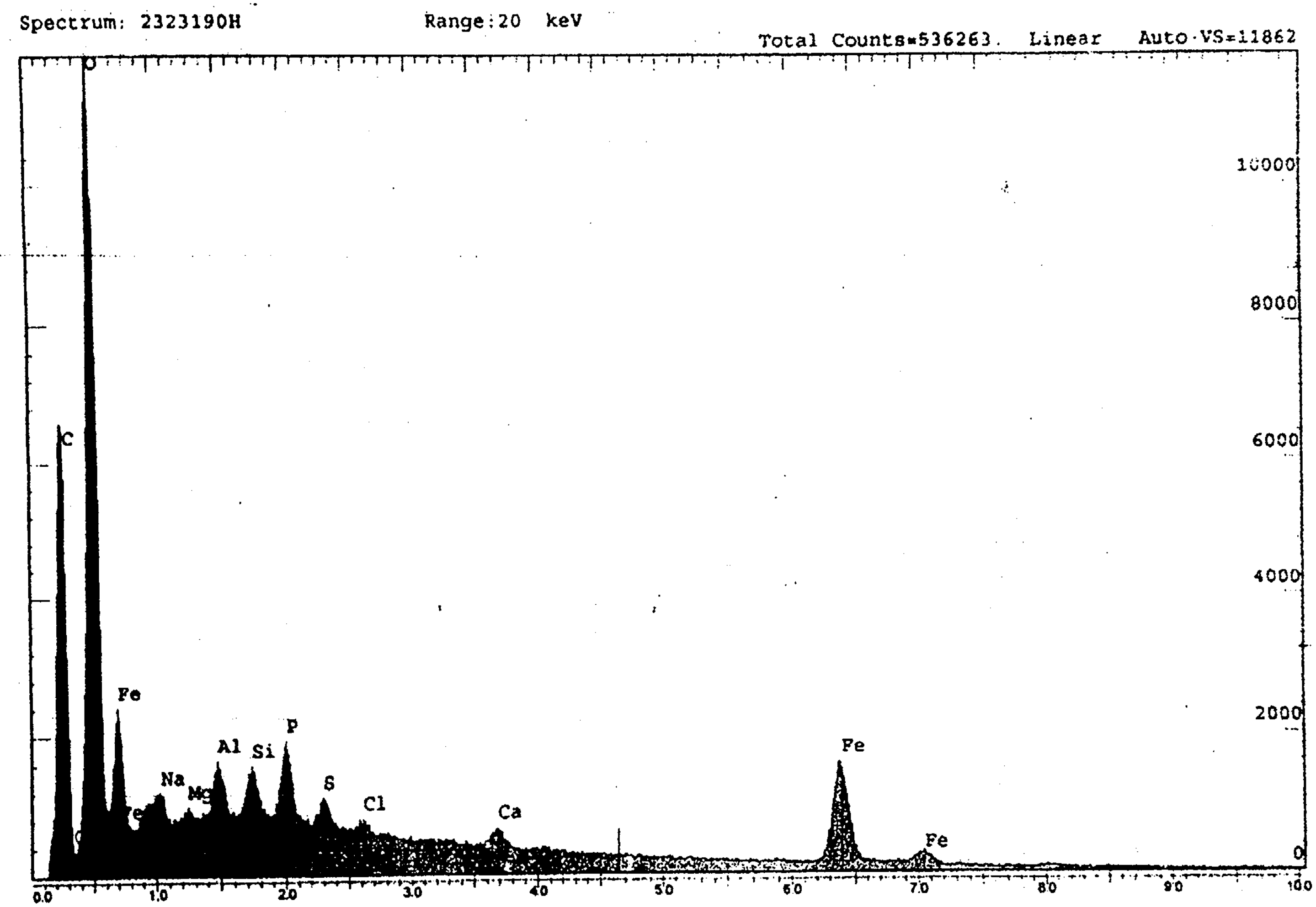


Figure 9. **EDS spectrum from an overall area of deposits on filter 7/16/99 White Bird.**

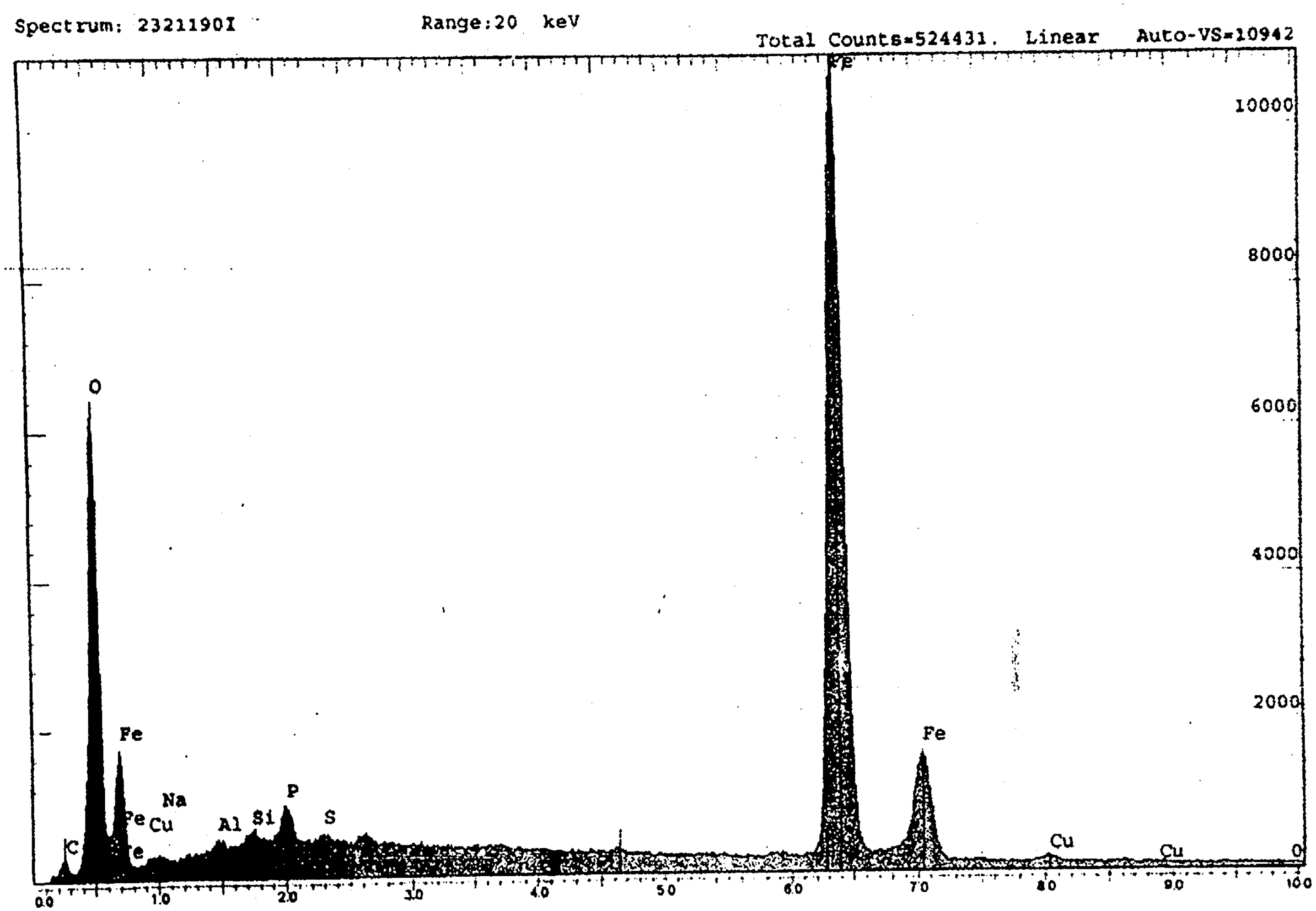
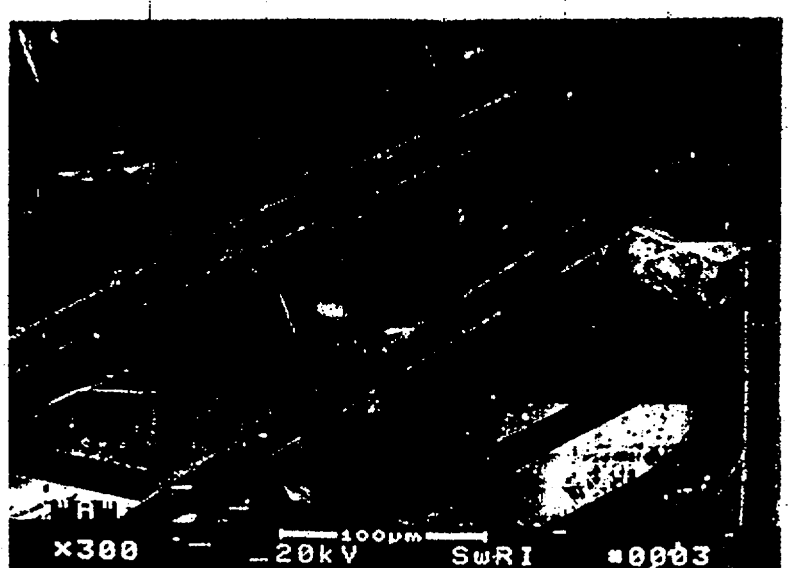
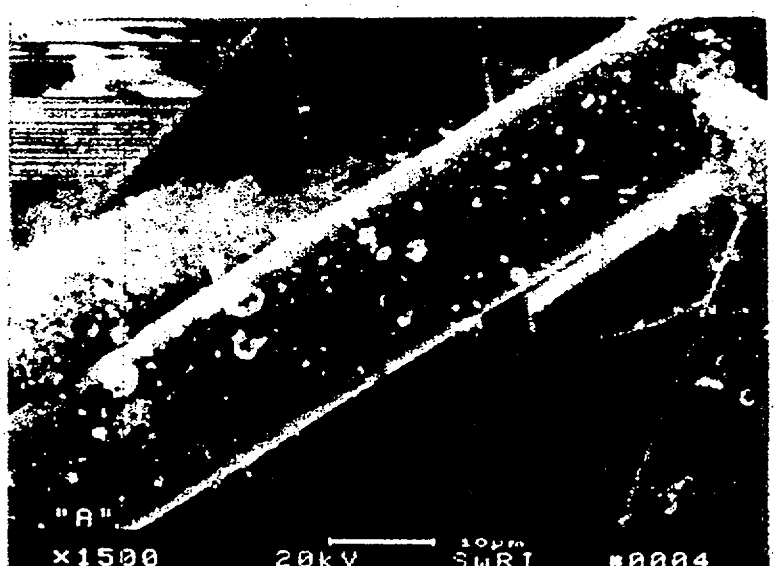


Figure 10, EDS spectrum from a single particle on filter 7/16/99 White Bird.

CR 1999-1800
Page 15 of 17

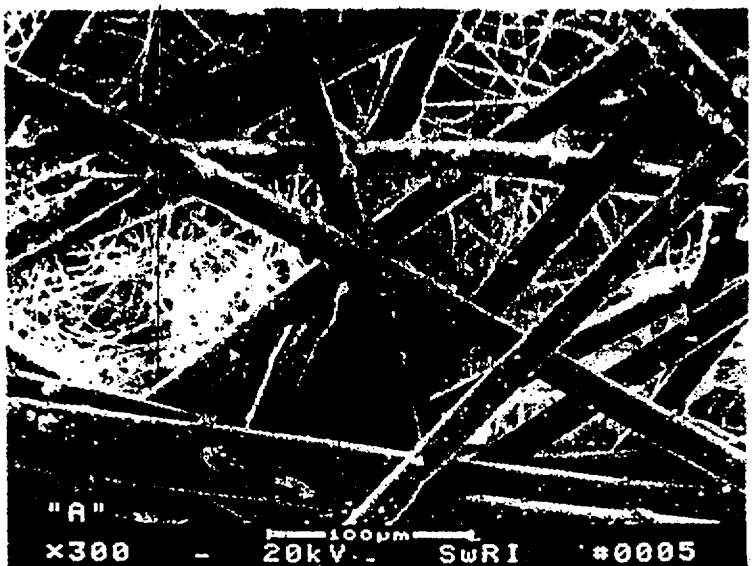


97614 (a)

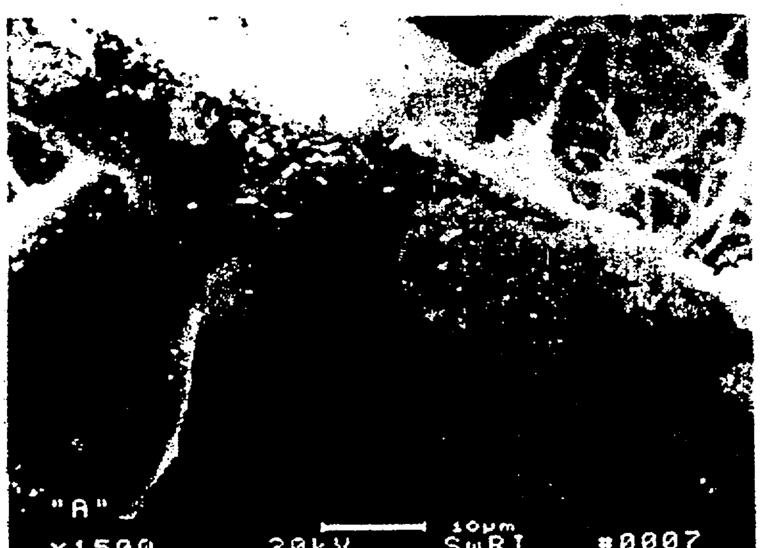


97615 (b)

Figure 11. **Scanning electron micrographs of an area of deposits on filter 4597BA 7/3/99@1400 following application of a gold/palladuim coating.**



97616 (a)



97617 (b)

Figure 12. **Scanning electron micrographs of a second area of deposits on filter 4597BA 7/3/99@1400 following application of a gold/palladium coating.**

RECORD END SHEET
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Reference L

005559.006391

ED 7632-10

POTENTIAL CONDITION ADVERSE TO QUALITY REPORT (PCAQR) | PCAQR NO. 98-0942 | PAGE 1

PART 1 INITIATION

INITIATOR

A. ISSUE, OBSERVATION, OR CONCERN

WHILE WORKING ON THE CLOSING OF THE FUEL TRANSFER TUBES IT WAS DECIDED THAT A CLEANLINESS INSPECTION WOULD NOT PASS. THE DISCUSSED COURSE OF ACTION WOULD BE TO TAKE A SAMPLE OF THE EXISTING ROD DUST, FINISH CLOSING COVERS. CHEMISTRY WILL ANALYZE THE MATERIAL AND DETERMINE IF THE MATERIAL WILL BE CLEANED OUT THE NEXT TIME THE TUBES ARE OPENED.

☐ Q-HOLD TAG APPLIED ☐ CONTINUED

EQUIPMENT IDENTIFICATION NO. (IF KNOWN)
P-23 & P-24

B. INITIATOR (Print)	SIGNATURE	ORGANIZATION	PHONE NO.	MAIL STOP	DATE
Jim Kovach	[signature]	MECH MAINT	7654	1002	5/6/98

SUPERVISOR

C. PCAQR SUBJECT
CLEANLINESS INSPECTION ON TRANSFER TUBES

D. SUPERVISOR (Print)	SIGNATURE	ORGANIZATION	PHONE NO.	MAIL STOP	DATE
M. G. PARKER	[signature]	MECH	7253	1002	5/6/98

PART 2 ☐ N/A STATUS AND REPORTABILITY

SHIFT SUPERVISOR

A. MODE / POWER	B. REPORTABILITY	C. OPERABLE
5 ~~6~~ / [illegible] 0%	☐ 1 HR ☐ 4 HR ☐ 24 HR ☒ N/A	☒ YES ☐ NO ☐ NON T.S.

D. IMMEDIATE ACTION TAKEN

Fuel Transfer Tubes are operable for CTMT closure. Evaluation will need to be completed prior to 12RFO.

☐ CONTINUED

E. SHIFT SUPERVISOR (Signature)	DATE	TIME
[signature]	5/6/98	1122

ED 1032P-1 (W)

POTENTIAL CONDITION ADVERSE TO QUALITY REPORT (PCAQR)	PCAQR NO. 1998 - 0942	PAGE 2

PART 4A **(CATEGORY 3) INITIAL ASSESSMENT**

A. ORGANIZATION: C H E M

DUE DATE: 7/31/98

B. APPARENT CAUSE

Interior surfaces of fuel transfer tubes (a Class B system) did not appear "metal clean" and were not free of particulate contaminants. The fuel transfer tubes contain oxidized reactor coolant during refueling periods and are only air dried during normal operating cycles. The foreign material may only be general rusting of the surfaces due to the aforementioned environmental conditions. Class B systems require metal clean sufaces unless the existing conditions are evaluated and found not to have a potential deleterious effect.

☐ CONTINUED

C. SYSTEM CAPABLE OF PERFORMING SPECIFIED FUNCTION

☒ N/A - Non Tech Spec and not a potentially reportable system.
☐ Yes
☐ No - Initiate new PCAQR if Part 2 was marked N/A or Operable / Yes or Non T.S.

D. 10CFR PART 21 REPORTABLE ☒ NO ☐ YES - NOTIFY REGULATORY AFFAIRS

E. SPECIFIC ACTION NECESSARY TO CORRECT CONDITION (Restoration)

Evaluate foreign material and determine if surfaces of fuel transfer tubes require cleaning prior to next flooding of canal. Per R. Edwards, additional CATS items will be generated if cleaning is required.

7/9/98

☐ CONTINUED

F. WORK COMPLETION DOCUMENTS

CATS Item #1 due January 1, 2000

RECE
JUN 4 1998
PCAQRB

☐ CONTINUED

G. ASME CODE ☒ NO ☐ YES, ANI REVIEW

ENGINEERING

EVALUATOR

	Name (Print)	Signature	Phone No.	Date
H. EVALUATOR (Print)	Rich Edwards	Richard Edwards	7555	6/4/98
I. SUPERVISOR (Print)	G W Gillespie		7268	6/4/98
J. CONCURRENCE - PCAQR REVIEW BOARD CHAIRMAN (Signature)				

[6392]

ED 793018

POTENTIAL CONDITION ADVERSE TO QUALITY REPORT (PCAQR)	PCAQR NO. 1998-0942	PAGE 3

PART 7 VERIFICATION

	YES	NO	N / A
A. APPROVED REMEDIAL ACTION HAS BEEN INITIATED AS DESCRIBED	X		
B. APPROVED CORRECTIVE ACTION TO PREVENT RECURRENCE HAS BEEN IMPLEMENTED AS DESCRIBED			X
C. Q-HOLD TAGS HAVE BEEN REMOVED			X
D. CONDITIONAL RELEASE HAS BEEN RESOLVED			X
E. STOP WORK ACTION HAS BEEN WITHDRAWN			X

F. DOCUMENTS REVIEWED

CATS

☐ CONTINUED

G. COMMENTS

NA

☐ CONTINUED

H. QA REVIEW OF AUDIT / SURVEILLANCE PCAQR NA			DATE
I. REGULATORY AFFAIRS REVIEW OF REPORTABLE PCAQR NA			DATE
J. EVALUATOR (Print) Earl E. Murphy	SIGNATURE Earl E. Murphy	PHONE NO. 8510	DATE 08/03/98
K. NSI MANAGER CONCURRENCE OF UNACCEPTABLE PCAQR NA			DATE

NUCLEAR SAFETY AND INSPECTION

006889 .006394

DMX16214 DAVIS-BESSE ACTIVITY TRACKING SYSTEM 08/04/98

DOCUMENT RELATED ITEMS

DOC TYPE/#: PCAQ 98-0942 SUMM: TRANSFER TUBES CLEANLINESS INSP

A/C/D CODE	ITEM TYPE	ITEM NUMBER	CLS	STATUS
_				
_				
_				
_				
_				
_				
_				
_				
_				
_				
_				
_				
_				
_				

PF2-UPDATE PF3-RESTART LIST PF4-RETRIEVE: T N
PF5-VIEW ITEM PF8-FORWARD PF9-S/T S PF10-DETAIL PF11-MENU

Reference M

NOP-LP-2001-01

CONDITION REPORT

TITLE: RE4597BA FITLER CHANGE OCCURRING MORE FREQUENTLY

CR Number 01-1110

ORIGINATION

DISCOVERY DATE	TIME	EVENT DATE	TIME	SYSTEM / ASSET#
4/23/2001	0830	04/23/2001	0830	079-01 RE4597BA

EQUIPMENT DESCRIPTION RE4597BA

DESCRIPTION OF CONDITION and PROBABLE CAUSE (if known) Summarize any attachments. Identify what, when, where, why, how.

Chemistry is changing the filters on RE4597BA more frequently. Filters were changed on 4/17/01 at 1623 , 4/20/01 at 2044, and 4/23/01 at 0915. All filter changes were at OPS request due to low flow. All filters contained Boron crystals.

SUPV COMMENTS / IMMEDIATE ACTIONS TAKEN (Discuss CORRECTIVE ACTIONS completed, basis for closure.)

RE4597BA filters were changed as requested.

QUALITY ORGANIZATION USE ONLY
Quality Org. Initiated ☐ Yes
Quality Org. Follow-up ☐ Yes ☐ No

IDENTIFIED BY (Check one)
☐ Individual/Work Group
☑ Supervision/Management
☐ Self-Revealed
☐ Internal Oversight
☐ External Oversight

ATTACHMENTS ☐ Yes ☑ No

ORIGINATOR	ORGANIZATION	DATE	SUPERVISOR	DATE	PHONE EXT.
SUTTON, B	CHEM	4/23/2001	SUTTON, B	4/23/2001	7575

PLANT OPERATIONS

SRO REVIEW	EQUIPMENT OPERABLE	EVALUATION REQUIRED	IMMEDIATE INVESTIGATION REQUIRED	ORGANIZATION NOTIFIED	MODE CHANGE RESTRAINT
☑ Yes ☐ No	☑ Yes ☐ No ☐ N/A	☑ Yes ☐ No	☐ Yes ☑ No	N/A	☐ Yes ☑ No

MODE	ASSOCIATED TECH SPEC NUMBER(S)	ASSOCIATED LCO ACTION STATEMENT(S)
N/A	N/A	#1 N/A
		#2
		#3

DECLARED INOPERABLE (Date / Time)	REPORTABLE?		APPLICABLE UNIT(S)
N/A	☐ Yes ☑ No ☐ Eval Required	One Hour N/A Four Hour N/A Other N/A	☑ U1 ☐ U2 ☐ Both

COMMENTS

Further Engineering evaluation of this issue required. Sample flows are being maintained above alarm setpoints by filter changes, therefore RE4597BA is operable.

Current Mode - Unit 1	Power Level - Unit 1	Current Mode - Unit 2	Power Level - Unit 2
1	100	N/A	N/A

SRO - UNIT 1	SRO - UNIT 2	DATE
Whalen, D	Myers, L	4/23/2001

CRPA / SUPV / MRB

CATEGORY / EVAL	ASSIGNED ORGANIZATION	DUE DATE
CA	PE	6/7/2001

TREND CODES

Process / Activity / Cause Code(s)			Comp Type / ID (If Cause T or W)		Resp Org
T	0575	T22	M	69	NONE

REGULATORY

REPORTABLE? ☐ Yes ☑ No ☐ LER No.

REPORTABILITY REVIEWER Cook, R

DATE 04/30/01

INVESTIGATION OPTIONS
☐ Generic Implications ☐ Part 21 ☐ Maint.Rule ☐ OE Evaluation

CLOSED BY | **DATE**

CORRECTIVE ACTION

NOP-LP-2001-05

CR Number: 01-1110

ORIGINATOR

CR Category:	Action Type:	Schedule Type:	CA Number:
CA	(P) PROCEDURE / INSTRUCTION	(A) Normal Work Management	1

Corrective Action Type:	Cause Code:	Resp Org:
(RA) Remedial Action	(C01) Environmental	PE

Description:

Requested Operations to swap the sample point for RE4587BA from top of the east D-ring to personnel hatch area.
This was accomplished on 4-27-01 at 0240. Since the sample point swap our filter change frequency have been reduced to once every 14 days according to Chemistry log entries.

Completed By:	Organization:	Date:	Phone:	Attachments:
CHUNG, G	PE	6/4/2001	7271	☐ Yes ☑ No

ACCEPT

If a Refueling Outage is required, Enter the Refueling Outage number:	Other Tracking #	Corrective Action Due Date:
☐ 1R ☐ 2R N/A	N/A	4/27/01

Approval: (Enter Name and Sign)	Section:	Date:
HOVLAND, B	PE	6/5/2001

QUALITY

Quality Organization Approval:	Date:

IMPLEMENTING ORG

Response:

The sample point swap was completed in according with DB-OP-06412 on 4-27-01. Since this swap of the our filter change fequency has been reduced to once every 14 days. However, the boron build up on the filter is still continuing. This problem can not be resolved until the RCS leaks is repaired.

Corrective Action Implementation Date: 4/27/01

☑ Signature indicates Corrective Action complete:
Completed By: CHUNG, G — Date: 6/4/2001

☑ Signature indicates verification for SCAQ CRs:
Implementing Organization Supervisor: — Date:

☑ Enter Name and Sign:
Implementing Organization Approval: CHUNG, G — Date: 6/4/2001

QUALITY VERIFIER

Comments:

Approval: — Date:

Reference N

NOP-LP-2001-01

CONDITION REPORT

CR Number 01-2795

TITLE: RE4597BA ALARM

ORIGINATION

DISCOVERY DATE	TIME	EVENT DATE	TIME	SYSTEM / ASSET#
10/22/2001	0750	10/22/2001	0750	079-01 RE4597BA

EQUIPMENT DESCRIPTION CONTAINMENT RADIATION MONITOR

DESCRIPTION OF CONDITION and PROBABLE CAUSE (if known) Summarize any attachments. Identify what, when, where, why, how.

RE4597BA alarmed on saturation. The filter was changed less than 19 hours previous to receiving the alarm. The frequency of filter changeout has been increasing for several months. This was documented on CRs 01-1110 (April2001) and 01-1822 (July 2001). Previous corrective actions have been unsuccessful and unsatisfactory.

SUPV COMMENTS / IMMEDIATE ACTIONS TAKEN (Discuss CORRECTIVE ACTIONS completed, basis for closure.)

Changed filters on RE4597BA.

QUALITY ORGANIZATION USE ONLY
Quality Org. Initiated ☐ Yes
Quality Org. Follow-up ☐ Yes ☐ No

IDENTIFIED BY (Check one)
☑ Individual/Work Group
☐ Supervision/Management
☐ Self-Revealed
☐ Internal Oversight
☐ External Oversight

ATTACHMENTS ☐ Yes ☑ No

ORIGINATOR	ORGANIZATION	DATE	SUPERVISOR	DATE	PHONE EXT.
SUTTON, B	CHEM	10/22/2001	EDWARDS, R	10/22/2001	7555

PLANT OPERATIONS

SRO REVIEW	EQUIPMENT OPERABLE	EVALUATION REQUIRED	IMMEDIATE INVESTIGATION REQUIRED	ORGANIZATION NOTIFIED	MODE CHANGE RESTRAINT
☑ Yes ☐ No	☑ Yes ☐ No ☐ N/A	☐ Yes ☑ No	☐ Yes ☑ No	N/A	☐ Yes ☑ No

MODE	ASSOCIATED TECH SPEC NUMBER(S)	ASSOCIATED LCO ACTION STATEMENT(S)
N/A	N/A	#1 N/A
		#2
		#3

DECLARED INOPERABLE (Date / Time)	REPORTABLE?		APPLICABLE UNIT(S)
N/A	☐ Yes ☑ No ☐ Eval Required	One Hour N/A Four Hour N/A Other N/A	☑ U1 ☐ U2 ☐ Both

COMMENTS

Changing the filter ensures that RE4597BA remains operable, thus operable marked yes.

Current Mode - Unit 1	Power Level - Unit 1	Current Mode - Unit 2	Power Level - Unit 2
1	100%	N/A	N/A

SRO - UNIT 1	SRO - UNIT 2	DATE
Patrick, R	Lewis, A	10/22/2001

CRPA / SUPV / MRB

CATEGORY / EVAL	ASSIGNED ORGANIZATION	DUE DATE
CA	PE	12/6/2001

TREND CODES

Process / Activity / Cause Code(s)			Comp Type / ID (If Cause T or W)		Resp Org
E	0050	C02			NONE

REGULATORY

REPORTABLE? ☐ Yes ☑ No ☐ LER No.

REPORTABILITY REVIEWER Bless, A

DATE 10/23/01

INVESTIGATION OPTIONS
☐ Generic Implications ☐ Part 21 ☐ Maint.Rule ☐ OE Evaluation

CLOSED BY	DATE

CORRECTIVE ACTION

NOP-LP-2001-05

CR Number: 01-2795

ORIGINATOR	**CR Category:** CA	**Action Type:** (Z) REMEDIATION	**Schedule Type:** (A) Normal Work Management	**CA Number:** 1
	Corrective Action Type: (RA) Remedial Action	**Cause Code:** (T06) Welding process		**Resp Org:** PE

Description:

Implemented temporary modification (TM) #01-0018 and #01-0019 to remove the iodine filter for both RE4597AA and BA thus eliminate the need for frequent filter changes. The frequency of the filter change was from once per shift to once per 7 days since the installation of the above TM's on 11-2-01.

Completed By:	**Organization:**	**Date:**	**Phone:**	**Attachments:**
CHUNG, G	PE	12/5/2001	7271	☐ Yes ☑ No

ACCEPT

If a Refueling Outage is required, Enter the Refueling Outage number: ☐ 1R ☐ 2R N/A	**Other Tracking #** TM#01-0018 & 19	**Corrective Action Due Date:** 12/6/01
Approval: (Enter Name and Sign) HOVLAND, B	**Section:** PE	**Date:** 12/5/2001

QUALITY

Quality Organization Approval: **Date:**

IMPLEMENTING ORG

Response:

The installation of the TM 01-0019 &01-0019 were completed on 11-2-01
Remove the iodine filter cartridge from RE4597AA and BA and replace it with a cartridge housing with its internal charcoal removed. Operations uses computer point R297 and R298 to know when to check RE4597AA and BA. Unlike the remote indicator controller (RIC), this computer point does not have reflash capability. Currently having channel #3 in alarm for extended periods will mask future alarms on this computer point. By replacing the filter cartridge with an empty one will prevent any future alarm from channel #3. The higher iodine level in CTMT atmosphere is a known condition.

Corrective Action Implementation Date: 11/2/01

■ Signature indicates Corrective Action complete:
Completed By: CHUNG, G **Date:** 12/5/2001

■ Signature indicates verification for SCAQ CRs:
Implementing Organization Supervisor: **Date:**

■ Enter Name and Sign:
Implementing Organization Approval: CHUNG, G **Date:** 12/5/2001

QUALITY VERIFIER

Comments:

Approval: **Date:**

Reference O

CONDITION REPORT

CR Number 01-1822

TITLE: INCREASING FREQUENCY OF RE4597BA FILTER CHANGEOUT

ORIGINATION

DISCOVERY DATE	TIME	EVENT DATE	TIME	SYSTEM / ASSET#
7/23/2001	0730	07/23/2001	0730	079-01 RE4597BA

EQUIPMENT DESCRIPTION N/A

DESCRIPTION OF CONDITION and PROBABLE CAUSE (if known) Summarize any attachments. Identify what, when, where, why, how.

The frequency at which the filters for RE4597BA are being changed out is increasing. The filter was last changed on Friday, 20 July 2001, at 1814. There were Boric Acid crystals on the particulate filter that was removed on Friday.

SUPV COMMENTS / IMMEDIATE ACTIONS TAKEN (Discuss CORRECTIVE ACTIONS completed, basis for closure.)

RE4597BA Filters were changed out

QUALITY ORGANIZATION USE ONLY
Quality Org. Initiated ☐ Yes
Quality Org. Follow-up ☐ Yes ☐ No

IDENTIFIED BY (Check one)
☐ Individual/Work Group
☑ Supervision/Management
☐ Self-Revealed
☐ Internal Oversight
☐ External Oversight

ATTACHMENTS ☐ Yes ☑ No

ORIGINATOR	ORGANIZATION	DATE	SUPERVISOR	DATE	PHONE EXT.
SUTTON, B	CHEM	7/23/2001	EDWARDS, R	7/23/2001	7555

PLANT OPERATIONS

SRO REVIEW	EQUIPMENT OPERABLE	EVALUATION REQUIRED	IMMEDIATE INVESTIGATION REQUIRED	ORGANIZATION NOTIFIED	MODE CHANGE RESTRAINT
☑ Yes ☐ No	☐ Yes ☐ No ☑ N/A	☐ Yes ☑ No	☐ Yes ☑ No	N/A	☐ Yes ☑ No

MODE	ASSOCIATED TECH SPEC NUMBER(S)	ASSOCIATED LCO ACTION STATEMENT(S)
N/A	N/A	#1 N/A
		#2
		#3

DECLARED INOPERABLE (Date / Time)	REPORTABLE?		APPLICABLE UNIT(S)
N/A	☐ Yes ☑ No ☐ Eval Required	One Hour N/A Four Hour N/A Other N/A	☑ U1 ☐ U2 ☐ Both

COMMENTS

No further comment.

Current Mode - Unit 1	Power Level - Unit 1	Current Mode - Unit 2	Power Level - Unit 2
1	100	N/A	N/A

SRO - UNIT 1	SRO - UNIT 2	DATE
Baldwin, J	Koch, S	7/23/2001

CRPA / SUPV / MRB

CATEGORY / EVAL	ASSIGNED ORGANIZATION	DUE DATE
NA	PE	9/21/2001

TREND CODES

Process / Activity / Cause Code(s)			Comp Type / ID (If Cause T or W)		Resp Org
T	0575	T18	M	29	NONE

REGULATORY

REPORTABLE? ☐ Yes ☑ No ☐ LER No.

REPORTABILITY REVIEWER Cook, R

DATE 07/24/01

INVESTIGATION OPTIONS
☐ Generic Implications ☐ Part 21 ☐ Maint.Rule ☐ OE Evaluation

CLOSED BY	DATE
	11/15/2001

CORRECTIVE ACTION

NOP-LP-2001-05

CR Number: 01-1822

CR Category:	Action Type:	Schedule Type:	CA Number:
NA	(G) EVALUATION	(A) Normal Work Management	1

Corrective Action Type:	Cause Code:	Resp Org:
(CM) Compensatory Measure	(T18) Flow obstruction	PE

ORIGINATOR

Description:

Currently we still have a small RCS leak in CTMT. This is indicated by the boron deposits on the clogged filters. Our plan is to repair the small RCS leak during the up coming refueling outage thus eliminate the necessity of frequent filter changes. Currently the criteria for filter change is either low flow alarm of 1.5 scfm or detector go into saturation. According to Chemistry Log, the frequency for RE4597BA filter change has varied from 2 to 7 days since the initiation of this CR. According to the Chemistry Richard Edwards, he is satisfy with the current replacement frequency. Based on the current trending history, Plant Engineering do not recommend any additional compensatory measure regard to the filter change on RE4597BA.

Completed By:	Organization:	Date:	Phone:	Attachments:
CHUNG, G	PE	8/31/2001	7271	☐ Yes ☑ No

ACCEPT

If a Refueling Outage is required, Enter the Refueling Outage number:	☐ 1R ☐ 2R N/A	Other Tracking #	Corrective Action Due Date:
		N/A	9/20/01

Approval: (Enter Name and Sign)	Section:	Date:
HOVLAND, B	PE	9/20/2001

QUALITY

Quality Organization Approval:	Date:

IMPLEMENTING ORG

Response:

Based on Plant Engineering trending since the initiation of this CR on 7-23-01, the current filter change frequency for RE4597BA is between 2 to 7 days. This is acceptable change frequency for Chemistry according to Richard Edwards. The plant Engineering recommend no other corrective action is at this time.

Corrective Action Implementation Date: 8/31/01

Signature indicates Corrective Action complete:
Completed By: CHUNG, G **Date:** 8/31/2001

Signature indicates verification for SCAQ CRs:
Implementing Organization Supervisor: **Date:**

Enter Name and Sign:
Implementing Organization Approval: CHUNG, G **Date:** 8/31/2001

QUALITY VERIFIER

Comments:

Approval: **Date:**

Reference P

Plant Issues

20-Jan-00

Linda Grffith ext. 7592

Component	Work Document	Status	Responsible Shop	ECD	Comments
CCW #2 MOTOR CABLE ISSUE	CR 1999-1648		SYSC		TEAM LEADER: DAVE GEISEN
CONTROLLED DOCUMENTS IN WORK ORDERS			QS	1/17/00	Linda Dohrman is point of contact
Essential/ Misc. AC action plan			PENG		
Forebay Level Issue			PENG		
HIGH CONTAINMENT ATMOSPHERE IMPURITIES			SYSC		A System Team meeting was held. Mod 99-0050 was initiated to reduce moisture in instrument lines.
RCS Leakage			SYME		UPDATE PROVIDED BY PE MANAGER

Davis-Besse Plant Issues

Issue: Since startup from the Cycle 12 mid-cycle outage, RE-4597AA and BA have exhibited a high rate of clogging of their particulate filters due to excessive dust/rust particles suspended in the containment atmosphere.

Actions To Date: After the Cycle 12 mid-cycle outage, particulate material started clogging the filters for RE4597AA and RE4597BA every 24 to 48 hours. The normal filter change interval for the last seven years has been monthly. The frequent filter replacements make it difficult to perform equipment maintenance and calibration while complying with Tech Specs for RCS leak detection. Prior to the mid-cycle outage, a 0.8 gpm leak in the Reactor Coolant System was causing a high boron concentration in the containment atmosphere. Boron was clogging the radiation monitor filters and was also collecting on the Containment Air Coolers (CACs). The filters for RE 4597AA were still being changed monthly but the RE 4597BA filters required a weekly replacement. White boron crystals were found on the filters which is similar to a condition observed in 1992 (PCAQR 92-0346). Containment entries for CAC cleaning were required every 8-10 days prior to the mid-cycle outage to maintain plenum pressure. During the mid-cycle outage valve work was performed which reduced the RCS leakage to <0.3 gpm. Other major activities include the CAC No.1 motor replacement and RCP1-2 motor bearing replacement. After the mid-cycle outage, containment entries were required initially at a 4 week interval to clean the CACs which currently has extended to about 12 weeks. A radiation monitor action plan was completed to check the RE4597AA/BA skid performance, inspect sample lines, check filter material, and analyze the particulate matter on the filters. The results indicate the low flow conditions are due to the particulate matter that is building up on the filters. The material was sent to Southwest Research Institute for analysis and was determined to be primarily an iron oxide (Refer to Condition Report 1999-1300). Temporary Modification 99-0022 installed four portable HEPA filtration units in containment to reduce the particulate concentration. The HEPA Units were removed and the prefilters were sampled which also confirmed the presence of iron. Sargent & Lundy (S&L) was contracted to independently assess the particulate problem. S&L concluded that the source of the particulate is from a small steam leak at a higher elevation in containment. The steam leak conclusion does not appear to be valid as the filter-clogging problem is gradually going away as CTMT temperature drops in the winter. Plant Engineering believes the more likely cause is corrosion of the CAC plenum that will be inspected in 12RFO.

Pending Actions: Continue to monitor the filter change frequency for the radiation monitors. Take periodic containment sump samples and analyze to help confirm source of leakage.

Timeline:

1. Perform Mode 3 and Mode 5 Containment Walkdowns to locate a potential steam leak – 12RFO (C. Hengge is KOP Team Leader)
2. Inspect the CAC inlet plenum - 12RFO (J. Otermat is KOP Team Leader)
3. Repair any identified RCS or Secondary Leaks – 12RFO
4. Run CTMT Purge in Mode 5 to remove the iron oxide from the Containment atmosphere – 12RFO
5. Paint/preserve any corroded surfaces that may be contributing to the particulate problem - 12RFO

RESPONSIBLE GROUP: PLANT ENGINEERING
RESPONSIBLE INDIVIDUAL: D. C. GEISEN

Plant Issues

16-Feb-00

Linda Grffith ext. 7592

	Component	Work Document	Status	Responsible Shop	ECD	Comments
1	CCW #2 MOTOR CABLE ISSUE	CR 1999-1648		SYSC		TEAM LEADER: DAVE GEISEN
2	CONTROLLED DOCUMENTS IN WORK ORDERS			QS	2/28/00	Linda Dohrman is point of contact
3	Essential/ Misc. AC action plan			SYSC		
4	Forebay Level Issue			SYME		
5	HIGH CONTAINMENT ATMOSPHERE IMPURITIES			SYSC		A System Team meeting was held. Mod 99-0050 was initiated t reduce moisture in instrument lines.
6	RCS Leakage			SYME		UPDATE PROVIDED BY PE MANAGER
7	SPDS & PLANT CMPTR			G. Hayes		

Davis-Besse Plant Issues

Issue: Since startup from the Cycle 12 mid-cycle outage, RE-4597AA and BA have exhibited a high rate of clogging of their particulate filters due to excessive dust/rust particles suspended in the containment atmosphere.

Actions To Date: After the Cycle 12 mid-cycle outage, particulate material started clogging the filters for RE4597AA and RE4597BA every 24 to 48 hours. The normal filter change interval for the last seven years has been monthly. The frequent filter replacements make it difficult to perform equipment maintenance and calibration while complying with Tech Specs for RCS leak detection. Prior to the mid-cycle outage, a 0.8 gpm leak in the Reactor Coolant System was causing a high boron concentration in the containment atmosphere. Boron was clogging the radiation monitor filters and was also collecting on the Containment Air Coolers (CACs). The filters for RE 4597AA were still being changed monthly but the RE 4597BA filters required a weekly replacement. White boron crystals were found on the filters which is similar to a condition observed in 1992 (PCAQR 92-0346). Containment entries for CAC cleaning were required every 8-10 days prior to the mid-cycle outage to maintain plenum pressure. During the mid-cycle outage valve work was performed which reduced the RCS leakage to <0.3 gpm. Other major activities include the CAC No.1 motor replacement and RCP1-2 motor bearing replacement. After the mid-cycle outage, containment entries were required initially at a 4 week interval to clean the CACs which currently has extended to about 12 weeks. A radiation monitor action plan was completed to check the RE4597AA/BA skid performance, inspect sample lines, check filter material, and analyze the particulate matter on the filters. The results indicate the low flow conditions are due to the particulate matter that is building up on the filters. The material was sent to Southwest Research Institute for analysis and was determined to be primarily an iron oxide (Refer to Condition Report 1999-1300). Temporary Modification 99-0022 installed four portable HEPA filtration units in containment to reduce the particulate concentration. The HEPA Units were removed and the prefilters were sampled which also confirmed the presence of iron. Sargent & Lundy (S&L) was contracted to independently assess the particulate problem. S&L concluded that the source of the particulate is from a small steam leak at a higher elevation in containment. The steam leak conclusion does not appear to be valid as the filter-clogging problem is gradually going away as CTMT temperature drops in the winter. Plant Engineering believes the more likely cause is corrosion of the CAC plenum that will be inspected in 12RFO.

Pending Actions: Continue to monitor the filter change frequency for the radiation monitors. Take periodic containment sump samples and analyze to help confirm source of leakage.

Timeline:

1. Perform Mode 3 and Mode 5 Containment Walkdowns to locate a potential steam leak – 12RFO (C. Hengge)
2. Inspect the CAC inlet plenum, measure zinc coating and paint if necessary - 12RFO (J. Otermat is KOP Team Leader)
3. Repair any identified RCS or Secondary Leaks – 12RFO
4. Run CTMT Purge in Mode 5 to remove the iron oxide from the Containment atmosphere – 12RFO
5. Paint/preserve any corroded surfaces that may be contributing to the particulate problem - 12RFO

RESPONSIBLE GROUP: PLANT ENGINEERING
RESPONSIBLE INDIVIDUAL: D. C. GEISEN

Plant Issues List

March 17, 2000

Issue	Responsible Organization/ Individual	ECD	Comments	MCTM Presentation Date
1. CCW #2 Motor Cable Issue	Plant Engineering/ Dave Geisen	12RFO	CR 1999-1648	March 3, 2000
2. Essential/Misc AC	Plant Engineering Dave Geisen	May, 2001	Project 00-1003 will ensure all scoped breakers (168) will be refurbished	March 6, 2000
3. Forebay Level Issue	Plant Engineering Glenn McIntyre	August, 2000	ECD is for CATPR completion	March 13, 2000
4. High Containment Atmospheric Impurities	Systems Engineering Bob Hovland	12RFO		March 17, 2000
5. RCS Leakage	Systems Engineering Craig Hengge	12RFO	12RFO Mode 3 walkdown plan	March 24, 2000
6. Review of Design Basis for Switchyard	Regulatory Affairs Jim Freels	To Be Determined		March 21, 2000
7. SPDS and Plant Computer	Computer Engineering Greg Hayes	To Be Determined		March 23,2000
8. ANO Decay Heat Issue	Design Basis Engrg. John Hartigan	To Be Determined	CR 2000-0271	March 20, 2000

Davis-Besse Plant Issues

Issue: Since startup from the Cycle 12 mid-cycle outage, RE-4597AA and BA have exhibited a high rate of clogging of their particulate filters due to excessive dust/rust particles suspended in the containment atmosphere.

Actions To Date: After the Cycle 12 mid-cycle outage, particulate material started clogging the filters for RE4597AA and RE4597BA every 24 to 48 hours. The normal filter change interval for the last seven years has been monthly. The frequent filter replacements make it difficult to perform equipment maintenance and calibration while complying with Tech Specs for RCS leak detection. Prior to the mid-cycle outage, a 0.8 gpm leak in the Reactor Coolant System was causing a high boron concentration in the containment atmosphere. Boron was clogging the radiation monitor filters and was also collecting on the Containment Air Coolers (CACs). The filters for RE 4597AA were still being changed monthly but the RE 4597BA filters required a weekly replacement. White boron crystals were found on the filters which is similar to a condition observed in 1992 (PCAQR 92-0346). Containment entries for CAC cleaning were required every 8-10 days prior to the mid-cycle outage to maintain plenum pressure. During the mid-cycle outage valve work was performed which reduced the RCS leakage to <0.3 gpm. Other major activities include the CAC No.1 motor replacement and RCP1-2 motor bearing replacement. After the mid-cycle outage, containment entries were required initially at a 4 week interval to clean the CACs which currently has extended to about 12 weeks. A radiation monitor action plan was completed to check the RE4597AA/BA skid performance, inspect sample lines, check filter material, and analyze the particulate matter on the filters. The results indicate the low flow conditions are due to the particulate matter that is building up on the filters. The material was sent to Southwest Research Institute for analysis and was determined to be primarily an iron oxide (Refer to Condition Report 1999-1300). Temporary Modification 99-0022 installed four portable HEPA filtration units in containment to reduce the particulate concentration. The HEPA Units were removed and the prefilters were sampled which also confirmed the presence of iron. Sargent & Lundy (S&L) was contracted to independently assess the particulate problem. S&L concluded that the source of the particulate is from a small steam leak at a higher elevation in containment. The steam leak conclusion does not appear to be valid as the filter-clogging problem is gradually going away as CTMT temperature drops in the winter. Plant Engineering believes the more likely cause is corrosion of the CAC plenum that will be inspected in 12RFO.

Pending Actions: Continue to monitor the filter change frequency for the radiation monitors. Take periodic containment sump samples and analyze to help confirm source of leakage.

Timeline:

1. Perform Mode 3 and Mode 5 Containment Walkdowns to locate a potential steam leak – 12RFO (C. Hengge)
2. Inspect the CAC inlet plenum, measure zinc coating and paint if necessary - 12RFO (J. Otermat is KOP Team Leader)
3. Repair any identified RCS or Secondary Leaks – 12RFO
4. Run CTMT Purge in Mode 5 to remove the iron oxide from the Containment atmosphere – 12RFO
5. Paint/preserve any corroded surfaces that may be contributing to the particulate problem - 12RFO

RESPONSIBLE GROUP: PLANT ENGINEERING
RESPONSIBLE INDIVIDUAL: D. C. GEISEN

Reference Q

October 8, 1999

Mr. Guy G. Campbell
Vice President - Nuclear
FirstEnergy Nuclear Operating Company
Davis-Besse Nuclear Power Station
5501 North State Route 2
Oak Harbor, OH 43449-9760

SUBJECT: DAVIS-BESSE INSPECTION REPORT 50-346/99010(DRP)

Dear Mr. Campbell:

On September 13, 1999, the NRC completed an inspection at your Davis-Besse site. The enclosed report presents the results of that inspection.

Overall, your facility was operated in a conservative and conscientious manner. However, the inspectors identified that important-to-safety doors within the facility have been either left open or blocked open for convenience on a number of occasions over the past several months. It appears that there is a general lack of sensitivity amongst your staff to the importance of these doors.

Based on the results of this inspection, the NRC has determined that a violation of NRC requirements occurred. This violation was reported to the NRC in a licensee event report and concerned the failure of your staff to conduct a timely engineering evaluation following excessive cooldown of the pressurizer during the shutdown for the recent maintenance outage at the station. This violation is being treated as a Non-Cited Violation, consistent with Appendix C of the Enforcement Policy. This Non-Cited Violation is described in the subject inspection report. If you contest the violation or the severity level of this Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region III, and the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if you choose to provide one, will be placed in the NRC Public Document Room.

Sincerely,

Original signed by
Thomas J. Kozak

Thomas J. Kozak, Chief
Reactor Projects Branch 4

Docket No. 50-346
License No. NPF-3

Enclosure: Inspection Report 50-346/99010(DRP)

cc w/encl: J. Stetz, Senior Vice President - Nuclear
J. Lash, Plant Manager
J. Freels, Manager, Regulatory Affairs
M. O'Reilly, FirstEnergy
State Liaison Officer, State of Ohio
R. Owen, Ohio Department of Health
C. Glazer, Chairman, Ohio Public
Utilities Commission

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if you choose to provide one, will be placed in the NRC Public Document Room.

Sincerely,

/s/Thomas J. Kozak

Thomas J. Kozak, Chief
Reactor Projects Branch 4

Docket No. 50-346
License No. NPF-3

Enclosure: Inspection Report 50-346/99010(DRP)

cc w/encl: J. Stetz, Senior Vice President - Nuclear
J. Lash, Plant Manager
J. Freels, Manager, Regulatory Affairs
M. O'Reilly, FirstEnergy
State Liaison Officer, State of Ohio
R. Owen, Ohio Department of Health
C. Glazer, Chairman, Ohio Public
Utilities Commission

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-346
License No:	NPF-3
Report No:	50-346/99010(DRP)
Licensee:	Toledo Edison Company
Facility:	Davis-Besse Nuclear Power Station
Location:	5501 N. State Route 2 Oak Harbor, OH 43449-9760
Dates:	August 2 through September 13, 1999
Inspectors:	K. Zellers, Senior Resident Inspector Christine Lipa, Senior Resident Inspector, Perry
Approved by:	Thomas J. Kozak, Chief Reactor Projects Branch 4 Division of Reactor Projects

EXECUTIVE SUMMARY

Davis-Besse Nuclear Power Station
NRC Inspection Report 50-346/99010(DRP)

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection.

Operations

- Overall, the facility was operated in a conservative and conscientious manner (Section O1.1).

- The inspectors concluded that plant personnel exhibited a lack of sensitivity to the control of doors important-to-safety throughout the plant as evidenced by the identification that doors had either been left open or had been blocked open on several occasions (Section O1.2).

- Operators responded promptly and thoroughly to a loss of cooling water flow to the hydrogen cooling system (Section O1.3).

- The inspectors concluded that shift turnovers were more thorough than in past years. Detracting from this was a failure of operators to activate the CCW system inoperability status light when the system was inoperable, the failure of the oncoming shift to recognize the light was not activated, and the failure of operators to print and place shift logs in the unit log book on two occasions (Section O1.4).

- The restricted change process did not require that the body of a procedure be changed which could result in procedures not being performed as intended (Section O3.1).

Maintenance

- Activities were planned and performed in a risk-informed manner. Pre-evolution briefs heightened personnel awareness of the potential impact of work activities. Engineering personnel provided support to maintenance activities and coordinated the more complex activities (Section M1.4).

- The impact of long-term scaffolding was not being rigorously reviewed (Section M1.4).

- Fiberglass ladders in battery rooms were not fully insulated to maximize protection to personnel and equipment (Section M1.4).

Engineering

- A Non-Cited Violation of Technical Specifications occurred when the licensee failed to perform an engineering evaluation of the pressurizer after a cooldown of 160 degrees in 1 hour occurred and prior to exceeding 500 psig reactor coolant system pressure. The apparent root causes were unclear procedural guidance and untimely corrective actions (Section E8.1).

Report Details

Summary of Plant Status

The plant was operated at nominally 100 percent power throughout the inspection period, except for brief, small reductions of power for testing.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors attended management meetings, reviewed Condition Reports (CRs), attended shift briefs, and questioned plant personnel on a continuing basis. Operators controlled plant maintenance and testing activities in an effective manner. Degraded conditions were placed into the corrective action system. Operations managers effectively communicated pertinent concerns to operations personnel in a timely manner. Plant management was aware of and prioritized efforts to address adverse conditions. Control room operators were alert and cognizant of plant activities. An example of good questioning attitude and attention-to-detail was exhibited when an equipment operator identified mis-labeled drain system valves while hanging a tagout. The inspectors concluded that, overall, the facility was operated in a conservative and conscientious manner.

O1.2 Control of Important Plant Doors

a. Inspection Scope (71707)

The inspectors reviewed the licensee's program for control of important-to-safety doors at the station.

b. Observations and Conclusions

The boric acid addition tank (BAAT) room door, which is a high energy line break door, serves to protect important plant equipment from the effects of a high energy line failure. This door was found open on July 23 and September 1, 1999. These events were documented in CRs 1999-1262 and 1999-1471, respectively. The apparent cause for the door being left open was that its closing mechanism did not overcome the resistance of the floor sweep when plant employees passed through the door. Contributing to these two instances was that plant employees failed to check that the door was closed behind them after they passed through it.

The inspectors also noted that there have been several other occasions of poor door control in the past, including negative pressure boundary doors and fire doors being left open, and important doors being blocked open for convenience. Additionally, the licensee recently submitted licensee event report (LER) 1999-002, "Both Trains of

Emergency Ventilation Rendered Inoperable Due to Unattended Open Door," which was another example of improper door usage. These items in the aggregate, indicate an insensitivity of plant personnel towards door usage.

Operations management has recently heightened employee sensitivity to door control by instructing equipment operators to challenge other station personnel to self-check that doors are closed behind them and by challenging managers to improve performance in this area. Additionally, a memorandum concerning door control was distributed to all site personnel to heighten the sensitivity of the importance of proper door control.

c. Conclusions

The inspectors concluded that plant personnel exhibited a lack of sensitivity to the control of doors important-to-safety throughout the plant as evidenced by the identification that doors had either been left open or had been blocked open on several occasions.

O1.3 Operator Response to a Loss of Cooling Water to the Generator Hydrogen Cooling System

a. Inspection Scope (71707)

The inspector conducted a routine walkdown of the control room on August 12, 1999.

b. Observations and Findings

Annunciator 16-1-E (main generator hydrogen gas pressure high) and 16-3-E (main generator hydrogen gas outlet temperature high) came into alarm at about 11:26 a.m. A control room reactor operator (RO) immediately checked the cooling water flow to the hydrogen cooling system and noted very little flow. He immediately informed control room personnel and the zone operator of the condition. The control room senior reactor operator used the annunciator response procedure to respond to the annunciators. The zone operator determined that the normally open cooling water control valve for the hydrogen cooling system was closed. At 11:29, with the outside assistant shift supervisor present, the zone operator placed the cooling water control valve in manual control and opened it to restore cooling water flow to the hydrogen cooling system. Annunciators 16-1-E and 16-3-E reset by 11:31 after the hydrogen cooling system cooling flow was restored. As a result of the condition, a shift status brief was performed and testing activities were suspended. It was determined that control logic for the valve had failed which caused the valve to close.

The temperature setting for annunciator 16-3-E was previously set conservatively low and, as a result, the annunciator was often in alarm. To reduce distractions to plant operators and improve their ability to recognize degraded conditions, the alarm setpoint was raised to clear the alarm condition. The inspectors determined that this effort contributed to operator's quick response to the loss of cooling water flow to the hydrogen cooling system.

c. Conclusions

Operators responded promptly and thoroughly to a loss of cooling water flow to the hydrogen cooling system.

O1.4 Conduct of Turnovers (71707)

During routine observations of shift turnovers, the inspectors noted that the turnovers were conducted more thoroughly than in past years. Contributing to this improvement was that the shift briefs were conducted in the work support center instead of the control room (which minimized distractions and was a better environment), and that shift turnover sheets were more detailed. However, the inspectors identified two instances where operators exhibited inattention-to-detail associated with shift turnovers. In the first instance, the inspectors observed that operators failed to activate the component cooling water system inoperability status light in the control room when the component cooling water (CCW) system was made inoperable. Further, although operators on the oncoming shift were aware the system was inoperable, they did not recognize that the inoperability light was not illuminated. Operations management generated CR 1999-1507 to document the observation. In the second instance, the inspectors identified that the official unit log book was missing log entries for an entire shift on two different occasions. The inspectors were informed that the operators routinely read the previous shifts' logs on a plant computer in which they were generated. However, it was management's expectation that the logs be printed and placed in the official unit log book at the end of each shift. The licensee indicated that the operators forgot to print the logs and place them in the log book at the end of their shift. In response to the observation, shift management required that the unit log be printed out on a shift basis by including it on an operator activity log. The inspectors concluded that shift turnovers were more thorough than in past years. Detracting from this was a failure of operators to activate the CCW system inoperability status light when the system was inoperable, the failure of the oncoming shift to recognize the light was not activated, and the failure of operators to print and place shift logs in the unit log book on two occasions.

O2 Operational Status of Facilities and Equipment

O2.1 System Walkdowns (71707)

The inspectors walked down the accessible portions of the following engineered safety features (ESF) and important-to-safety systems during the inspection period:

- emergency diesel generators
- component cooling water
- low voltage switchgear
- makeup pumps
- high pressure injection
- low pressure injection
- auxiliary feedwater

No substantive concerns were identified as a result of the walkdowns. System lineups and major flowpaths were verified to be consistent with plant procedures/drawings and the Updated Safety Analysis Report (USAR). Pump/motor fluid levels were within their normal bands. Minor oil and fluid leaks were noted on occasion. The inspectors informed plant management of poor housekeeping in the turbine building truck bay. Management stated that the area was not up to their standards and initiated actions to improve the cleanliness in the area.

O3 Operations Procedures and Documentation

O3.1 Temporary Procedure Changes

a. Inspection Scope (71707)

The inspectors questioned control room operators knowledge of a temporary modification that had been made to a control room annunciator.

b. Observations and Findings

Annunciator 15-5-B (electro hydraulic control panel trouble), was in alarm due to a failed input. The licensee implemented Temporary Modification (TM) 99-0024 which authorized lifting a lead from the failed input to allow the annunciator to operate normally in response to other alarm conditions. The TM was to remain in place until the failed input was repaired. The inspectors questioned control room operators as to how the actions taken in accordance with the TM were reflected in the annunciator response procedure. An operator informed the inspectors that the change was not referenced in the body of the alarm response procedure but that it was accounted for in the procedure by using the restricted change process. The restricted change process is used for procedure changes that are temporary and is accomplished by attaching the change to the front of a procedure. However, the process does not require that changes be made to the body of the procedure. Plant management expected that plant personnel would check the restricted changes to a procedure prior to its use. However, the inspectors have observed that control room operators have not always checked for a restricted procedure change prior to using annunciator response procedures. The inspectors were concerned that not including procedure changes into procedure bodies could result in not performing procedures the way they are intended. In response, operations management stated that the current process could be a precursor to a human error event and generated CR 1999-1506 to evaluate the process.

c. Conclusions

The restricted change process did not require that the body of a procedure be changed which could result in procedures not being performed as intended.

O8 Miscellaneous Operations Issues

O8.1 Closeout of Old Violations in Accordance with New Enforcement Policy Guidance

The Severity Level IV violations listed below were issued in Notices of Violation prior to the March 11, 1999, implementation of the NRC's new policy for treatment of Severity Level IV violations (Appendix C of the Enforcement Policy). Because these violations would have been treated as Non-Cited Violations in accordance with Appendix C, they are being closed out in this report.

- Violation number 50-346/98009-03. This violation is in the licensee's corrective action program as TERMS A19355.
- Violation number 50-346/98005-02. This violation is in the licensee's corrective action program as TERMS A19325.
- Violation numbers 50-346/98002-01a, and 50-346/98002-01b. These violations are in the licensee's corrective action program as TERMS A19203, and A19205.
- Violation number 50-346/98002-03. This violation is in the licensee's corrective action program as TERMS A19204.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

Maintenance and surveillance activities were planned and performed taking into account risk insights developed by risk assessment personnel. The heightened risk sensitivity of station personnel resulted in the request and approval of a license amendment request to extend the frequency of relatively high risk control rod drive breaker testing from a monthly to a quarterly periodicity. The extended time period required to perform this test will result in the reduction of overall plant risk.

M1.2 Maintenance and Surveillance Activities (61726, 62707)

The following maintenance and surveillance testing activities were observed/reviewed during the inspection period:

- Incore Instrumentation Channel Check, DB-NE-03233
- EDG 2 Monthly, DB-SC-03071
- D1 Bus Undervoltage Units Monthly Functional Test, DB-ME-03046
- SFAS 18-Month Interchannel Logic Test, DB-SC-03115
- Replace Defective LEDs on RIC 4597BB, MWO-99-001340
- Containment Personnel Hatch Local Leak Rate Test, DB-PF-03291

- Foxboro I/I Current Repeater Calibration, DB-MI-05233
- HV 5443A,B,&C PMs, MWO-99-1574-0000

Testing results passed acceptance criteria. Maintenance was accomplished in accordance with maintenance procedures. Post maintenance testing demonstrated the functionality of equipment before return to service. Minor procedure discrepancies were properly dispositioned. On occasion, system engineers observed the performance of testing activities. System engineers coordinated and provided technical assistance for system outages. Operators were pre-briefed on the impact of maintenance or testing activities. When applicable, an operating experience report would be used that pertained to the test or maintenance activity to heighten the importance to station personnel of performing the activity properly. Repairs to a failed auxiliary contact in a breaker associated with the emergency ventilation system was conducted in an expeditious manner.

M1.3 Scaffolding

a. Inspection Scope (71707)

The inspectors reviewed the licensee's control of scaffolding.

b. Observations and Findings

The inspectors noted that some scaffolding remained in the plant for extended periods of time because of frequent usage (e.g., scaffolding constructed to perform monthly emergency battery light testing). The scaffolding that was installed on a long-term basis was reviewed yearly by maintenance services personnel to determine its acceptability. The inspectors questioned licensee management about the rigor used in reviewing the long-term installation of scaffolding. For example, while scaffolding could impact the ability of equipment operators, fire protection personnel, or plant personnel to respond to an event or a fire, it was not clear that these issues were considered during the review. In response, the maintenance manager indicated that he would review the long-term scaffolding review process.

The inspectors also noted that although the scaffolding procedure restricted the use of metal for scaffolding used in the battery rooms, and required that metal tools over 6 inches long be insulated in order to minimize the potential for high energy battery accidents, it allowed the use of fiberglass ladders. Fiberglass ladders are a superior choice over metal ladders for safety considerations; however, fiberglass ladders have metal rungs and hardware that may still pose a safety hazard in the vicinity of a battery. The inspectors noted that the procedure did not require these metal rungs or hardware be insulated, and an inspection of the battery rooms determined that a fiberglass ladder was present with non-insulated rungs and hardware.

M1.4 Conclusions on the Conduct of Maintenance

Activities were planned and performed in a risk-informed manner. Pre-evolution briefs heightened personnel awareness of the potential impact of work activities. Engineering personnel provided support to maintenance activities and coordinated the more complex activities. However, the impact of long-term scaffolding was not being rigorously reviewed, and fiberglass ladders in battery rooms were not fully insulated to maximize protection to personnel and equipment.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) LER 50-346/1998-011-01: manual reactor trip due to component cooling water system leak. This LER update provided clarifying information on the operability and functionality of the auxiliary feedwater system during the event. Additionally, updated corrective actions were provided. The original LER was closed out in Inspection Report 50-346/1999-009.

M8.2 (Closed) LER 50-346/1998-009-01: reactor coolant system spray valve degraded with two of eight body to bonnet nuts missing. This LER update provided the results of a finite-element-analysis for various configurations of missing nuts on pressurizer spray valve RC-2 and provided the conclusion that RC-2 would have performed its design function under design basis accident conditions for all nut configurations. Additionally it presented the results of extent of condition inspections done during a mid-cycle outage, the results of inspections done on valve RC-2, and other corrective action efforts. This event was discussed in Inspection Report 50-346/98021 and was dispositioned as a Severity Level III violation.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Containment Atmosphere Cleanup Efforts (37551)

The inspectors reviewed the licensee's continuing efforts to address suspended corrosion product particulates in the containment atmosphere that periodically affected the operation of the reactor coolant system leak detection system (RCSLDS). The RCSLDS was periodically affected when corrosion product particulates from the containment atmosphere plugged RCSLDS filters to the point that the air flow was less than required to obtain representative samples of the containment atmosphere for reactor coolant system (RCS) leak detection purposes. To address the situation, portable filtration units were placed into containment to clean up the air, which resulted in decreasing the frequency of RCSLDS degradations. The licensee concluded in its safety evaluation that the portable filters did not adversely affect the capability of the RCSLDS to perform its leakage detection function. However, the source of the corrosion product particulates was still unknown. The licensee planned to perform thorough inspections of the containment during the next refueling outage to detect the source.

E8 Miscellaneous Engineering Issues (92903)

E8.1 <u>(Closed) LER 50-346/1999-003-00</u>: failure to perform engineering evaluation for pressurizer cooldown rate exceeding Technical Specification (TS) limit. On April 25, 1999, during the reactor shutdown for the mid-cycle outage, operators noted that the pressurizer cooldown rate based on pressurizer temperature instrument TE RC15 indicated a 160 degree drop in a one-hour period. This occurred while filling the pressurizer from about 50 inches to 280 inches with the RCS at about 160 degrees (decay heat removal was providing core cooling) in accordance with procedure. Relatively cold water entered the pressurizer through the surge line at the bottom of the pressurizer and did not mix with hotter water in higher portions of the pressurizer. This cold slug of water moved up in level until the resistance temperature detector (RTD) became immersed, resulting in an almost step change of indicated temperature. Because the cold slug of water did not mix well with the hotter water in the higher portions of the pressurizer, saturation conditions at the steam/water interface was essentially unaffected and consequently, little change of RCS pressure was observed. Therefore, operators determined that the indicated temperature from TE RC15 was not valid because the correct pressurizer temperature should be based on the saturation temperature of the RCS pressure. The cooldown rate based on this method did not exceed the TS LCO 3.4.9.2. limit of 100 degrees in a one-hour period. Condition Report 1999-0656 was generated which requested that the situation be reviewed to determine the validity of using TE RC15 for pressurizer cooldown indication.

On July 26, 1999, engineering personnel reviewed CR 1999-0656 and determined that the initial resolution of this event was incorrect. The review determined that stratification of the pressurizer fluid existed and that TE RC15 accurately showed cooldown of the pressurizer lower shell and was therefore a valid indication. The pressurizer cooldown rate of 160 degrees per hour exceeded the 100 degrees per hour limit. The TS actions required that an engineering evaluation be performed to determine the effects of the condition on the fracture toughness of the pressurizer. An evaluation was completed on July 27 during which it was determined that the pressurizer was operable with a safety margin of 4.5 (greater than 1 was acceptable) and that the cooldown rate experienced had no effect on the pressurizer fatigue life and fracture toughness.

The licensee's apparent root cause determination stated that the guidance provided in the plant shutdown and cooldown operating procedure (DP-OP-06903) did not include sufficient information to provide operators with the information needed to monitor pressurizer cooldown limits. As initial actions to prevent recurrence, operators were to read the evaluation of the event and were given instructions to use the TE RC15 indication for monitoring pressurizer cooldown. A revision to the plant shutdown and cooldown procedure was initiated to provide information to prevent recurrence.

The inspectors determined that other factors contributed to the failure to perform the engineering evaluation within the required period. The licensee assumed that the initial determination that the pressurizer cooldown rate was not exceeded was correct and did not assign an aggressive review date to ensure that the situation was thoroughly evaluated before plant startup. Condition Report 1999-0656 was evaluated by system engineering personnel but was not given to design basis engineering personnel for review until the week of July 19. It was not until July 26, about 3 months after the event occurred, that design basis engineering personnel determined that the original disposition was incorrect. Additionally, regulatory affairs personnel discovered that an almost identical event happened on April 12,1998, (ref. PCAQR 1998-0547, PCAQR 1998-1172, and CR 1999-1110) and generated CR 1999-1339, to document and review the reasons for the missed opportunity to make changes to prevent recurrence.

Technical Specification 3.4.9.2.a. states, in part, that the pressurizer temperature shall be limited to a cooldown of 100 degrees in any one-hour period. The action statement for TS 3.4.9.2.a. states, in part, that with the pressurizer temperature limits in excess of any of the above limits, restore the temperature to within limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the fracture toughness properties of the pressurizer; determine that the pressurizer remains acceptable for continued operation or be in at least hot standby within the next 6 hours and reduce pressurizer pressure to less than 500 psig within the following 30 hours. On April 25, 1999, the pressurizer cooldown rate was 160 degrees in 1 hour. On May 8, 1999, the licensee raised coolant pressure above 500 psig. The inspectors concluded a violation of TS 3.4.9.2.a occurred when the licensee failed to perform an engineering evaluation of the pressurizer prior to exceeding 500 psig reactor coolant system pressure after the cooldown of 160 degrees in 1 hour occurred. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as LER 50-346/1999-003-00 **(NCV 50-346/1999010-01 (DRP)).**

E8.2 (Closed) IFI 50-346/97011-04(DRP): control of design calculations. This item was open pending inspection of the licensee's program for controlling design calculations. The inspectors completed this review with no regulatory or safety issues noted.

E8.3 (Closed) IFI 50-346/97011-05(DRP): control of instrument information sheets. This item was open pending evaluation of the interrelationships between surveillance procedures and instrument information sheets. The inspectors completed this review with no regulatory or safety issues noted.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 As Low As Reasonably Achievable (ALARA) Brief (71750)

The inspectors attended an ALARA brief for a containment entry to inspect portable filtration units. The brief was thorough, and personnel who participated in the brief provided good interaction and input.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on September 13, 1999. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. H. Lockwood, Supervisor, Compliance
D. L. Miller, Senior Engineer, Licensing
D. L. Eshelman, Manager, Operations
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T. J. Chambers, Supervisor, Quality Assurance

NRC

K. S. Zellers, Resident Inspector, Davis-Besse

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

<u>Opened</u>

50-346/99010-01(DRP)	NCV	Technical Specification violation for not performing an engineering evaluation for the pressurizer following a pressurizer cooldown in excess of TS limits.

<u>Closed</u>

50-346/99010-01(DRP)	NCV	Technical Specification violation for not performing an engineering evaluation for the pressurizer following a pressurizer cooldown in excess of TS limits.
50-346/98009-03(DRP)	VIO	failure to translate emergency sump design specs into USAR
50-346/98005-02(DRP)	VIO	inadequate control temperature service manifold isolation valves for supply hose
50-346/98002-01a(DRP)	VIO	failure to follow water balance inventory test procedure
50-346/98002-01b(DRP)	VIO	failure to follow procedure use and adherence procedure
50-346/98002-03(DRP)	VIO	failure to meet 10 CFR 50.72 one-hour reporting requirements
50-346/1998-011-01	LER	manual reactor trip due to component cooling water system leak
50-346/1998-009-01	LER	reactor coolant system spray valve degraded with two of eight body to bonnet nuts missing
50-346/1999-003-00	LER	failure to perform engineering evaluation for pressurizer cooldown rate exceeding TS limit
50-346/97011-04(DRP)	IFI	control of design calculations
50-346/97011-05(DRP)	IFI	control of instrument information sheets

<u>Discussed</u>

None

LIST OF ACRONYMS AND INITIALISMS USED

ALARA	As Low As Reasonably Achievable
BAAT	Boric Acid Addition Tank
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CRSRO	Control Room Senior Reactor Operator
ESF	Engineered Safety Feature
IFI	Inspection Followup Item
IR	Inspection Report
LCO	Limiting Condition for Operation
MWO	Maintenance Work Order
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
PCAQR	Potential Condition Adverse to Quality Report
PDR	Public Document Room
RCS	Reactor Coolant System
RCSLDS	Reactor Coolant System Leak Detection System
RO	Reactor Operator
RTD	Resistance Temperature Detector
TM	Temporary Modification
TS	Technical Specification
USAR	Updated Safety Analysis Report