March 22, 2004

Mr. Lew W. Myers
Chief Operating Officer
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 INTEGRATED INSPECTION REPORT 05000346/2004002

Dear Mr. Myers:

On February 14, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Davis-Besse Nuclear Power Station. The enclosed inspection report documents the inspection findings which were discussed on January 23, February 25, 26, and 27, 2004, with you or members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. For the entire inspection period, the Davis-Besse Nuclear Power Station was under the Inspection Manual Chapter (IMC) 0350 Process. The Davis-Besse Oversight Panel assessed inspection findings and other performance data to determine the required level and focus of followup inspection activities and any other appropriate regulatory actions.

The report documents three inspection findings of very low safety significance (Green), two of which involved violations of NRC requirements. The findings did not present any immediate safety concerns. Because the violations were of very low safety significance and were entered into your corrective action program, the NRC is treating these violations as Non-Cited Violations, consistent with Section VI.A of the NRC Enforcement Policy. In addition, one issue was reviewed under the NRC traditional enforcement process and was determined to be a Severity Level IV violation of NRC requirements. Because this violation was non-wilful, non-repetitive, and was entered into your corrective action program, the NRC is treating this issue as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

This report also documents the closure of two items on the NRC's Restart Checklist. Item 2.a, "Reactor Pressure Vessel Head Replacement," was resolved through our inspection of associated licensee activities and our independent inspections. Item 2.e, "High Pressure Injection Pump Internal Clearance and Debris Resolution," was closed based on our inspections and evaluations of the modifications associated with the high pressure injection pumps to resolve this issue.

If you contest the severity of any Non-Cited Violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region III, 801 Warrenville Road, Lisle, IL 60532-4351; the Director, Office of Enforcement, U. S. Nuclear Regulatory Commission, Washington DC 20555-001; and the NRC Resident Inspector at Davis-Besse.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure 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/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

John A. Grobe, Chairman
Davis-Besse Oversight Panel

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

Enclosure: Inspection Report 05000346/2004002
w/Attachments: Supplemental Information
TIA 2003-04, Evaluation of Modifications to the High Pressure Injection Pump

cc w/encl: The Honorable Dennis Kucinich
G. Leidich, President - FENOC
Plant Manager
Manager - Regulatory Affairs
M. O'Reilly, Attorney, FirstEnergy
Ohio State Liaison Officer
R. Owen, Administrator, Ohio Department of Health
Public Utilities Commission of Ohio
President, Board of County Commissioners
Of Lucas County
C. Koebel, President, Ottawa County Board of Commissioners
D. Lochbaum, Union Of Concerned Scientists
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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-346
License No:	NPF-3
Report No:	05000346/2004002
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Davis-Besse Nuclear Power Station
Location:	5501 North State Route 2 Oak Harbor, OH 43449-9760
Dates:	January 1, 2004, through February 14, 2004
Inspectors:	S. Thomas, Senior Resident Inspector J. Rutkowski, Resident Inspector M. Salter-Williams, Resident Inspector S. Campbell, Fermi Senior Resident Inspector M. Holmberg, Reactor Inspector T. Ploski, Senior Emergency Preparedness Inspector B. Jickling, Emergency Preparedness Inspector G. Costo, NRR Emergency Preparedness Specialist
Approved by:	Christine A. Lipa, Chief Branch 4 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000346/2004002; 1/1/2004 - 2/14/2004; Davis-Besse Nuclear Power Station; Adverse Weather Protection, Identification and Resolution of Problems, and Other Activities

This report covers a 6 week period of resident inspection. The inspection was conducted by resident and region based inspectors. Three green findings, two of which were associated with Non-Cited Violations, were identified. In addition, one Severity Level IV Non-Cited Violation was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be “Green” or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

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

Cornerstone: Emergency Preparedness

- Severity Level IV. The inspectors identified that the licensee had changed its standard emergency action level (EAL) scheme by revising one EAL’s criteria for an Unusual Event declaration due to the initiation of the Steam and Feedwater Rupture Control System as a result of a rapid depressurization of the secondary side. The inspectors determined that this EAL change decreased the effectiveness of the emergency plan, and that the licensee did not obtain prior NRC approval for this change, contrary to the requirements of 10 CFR 50.54(q).

  Because the issue affected the NRC’s ability to perform its regulatory function, it was evaluated with the traditional enforcement process as specified in Section IV.A.3 of the Enforcement Policy. According to Supplement VIII of the Enforcement Policy, this finding was determined to be a Severity Level IV because it involved a failure to meet a requirement not directly related to assessment and notification. Further, this problem was isolated to one EAL and was not indicative of a functional problem with the EAL scheme. Additionally, because the licensee entered this issue into its corrective action program and completed adequate corrective actions, this finding is being treated as a Severity Level IV Non-Cited Violation of 10 CFR 50.54(q). (Section 1EP4)

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance was self-revealed when, during performance of a functional test for the Steam Feedwater Rupture Control System (SFRCS) steam generator 2 differential pressure switch, the licensee did not perform the 1 hour action statement of Technical Specification 3.3.2.2. The pressure switch was isolated for a period of approximately 2 hours and 24 minutes without control room knowledge. This rendered the pressure switch incapable of sensing differential pressure and providing a signal, if needed, to the SFRCS actuation channel 2. Plant procedures require maintaining knowledge of the proper and actual status of Technical Specification listed equipment.

The finding was more than minor because it involved the configuration control and human performance attributes of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The issue was a Non-Cited Violation of Technical Specification 6.8.1 which required the implementation of written procedures governing plant operations. (Section 4OA5)

- Green. The inspectors identified a finding of very low safety significance and associated NCV for the licensee's failure to determine the cause and implement actions to prevent recurrence for the inadequate design changes (removed air accumulators) made to the air operated service water system valves at the outlet of the component cooling water heat exchangers. Although the licensee had implemented corrective measures for the service water valve design deficiencies, the licensee failed to recognize the need for a root cause investigation and to take actions to prevent recurrence for the inadequate modification process until questioned by the NRC inspectors.

  This finding was greater than minor because this example was associated with the Mitigating Systems Cornerstone and if left uncorrected, could potentially result in other inoperable safety related equipment or systems. The finding was determined to be of very low safety significance by management review, because the licensee had taken actions to restore the air operated service water valves to an operable configuration and, after identification by the inspectors, the licensee entered the failure to identify the cause(s) and implement action(s) to prevent recurrence for the inadequate modification into the corrective action program. This issue was a NCV of 10 CFR 50 Appendix B Criteria XVI, "Corrective Action." (Section 4OA2).

- Green. A finding of very low safety significance was identified by the inspectors for inadequate preparations for the onset of frazil ice conditions prior to January 6, 2004. Lack of coordination between licensee departments resulted in incomplete preparations prior to the onset of frazil ice conditions.

  The inspectors determined that the finding was more than minor because, if left uncorrected, it could contribute to the likelihood of those events that upset plant stability. Specifically, the failure to adequately prepare for frazil ice conditions could result in a plant shutdown. The finding was of very low safety significance because the finding: (1) was not associated with the likehood of primary or secondary system LOCA initiation; (2) did not contribute to the likelihood that mitigation systems would be unavailable; and (3) was not associated with fire or flood. No violation of NRC requirements occurred. (Section 1R01.1)

B. Licensee Identified Findings

Violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations are listed in Section 4OA7.

REPORT DETAILS

Summary of Plant Status

The plant was shutdown on February 16, 2002, for a refueling outage. During scheduled inspections of the control rod drive mechanism nozzles, significant degradation of the reactor vessel head was discovered. As a direct result of the need to resolve many issues surrounding the Davis-Besse reactor vessel head degradation, NRC management decided to implement IMC 0350, “Oversight of Operating Reactor Facilities in a Shutdown Condition With Performance Problems.” Significant dates for this extended outage were as follows:

- fuel was removed from the reactor on June 26, 2002;
- entered operational Mode 6 on February 19, 2003;
- fuel reload was completed on February 26, 2003;
- entered operational Mode 5 on March 12, 2003;
- entered operational Mode 4 on September 13, 2003;
- entered operational Mode 3 on September 14, 2003;
- completed the normal operating pressure test for the reactor coolant system and started cooldown to Mode 5 on September 30, 2003;
- entered operational Mode 4 on December 28, 2003; and
- entered operational Mode 3 on December 30, 2003.

On January 2, 2004, the licensee re-commenced a heatup and achieved normal operating pressure and temperature on January 5, 2004. On January 8, 2004, the licensee commenced a reactor plant cooldown from operational Mode 3 to Mode 4. This cooldown was required by Technical Specification (TS) due to the inoperability of one train of auxiliary feedwater. The plant entered Mode 4 on January 9, 2004. On January 26, 2004, the plant entered Mode 3 and attained normal operating pressure and temperature on January 28, 2004. For the entire inspection period, the Davis-Besse Nuclear Power Station was under the IMC 0350 Process.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

.1 Insufficient Preparations for Frazil Ice Conditions

a. Inspection Scope

The inspectors reviewed the licensee’s cold weather readiness by verifying cold weather design features and implementation of the licensee’s procedure DB-OP-06931, “Seasonal Plant Preparation Checklist.” The inspectors evaluated the licensee’s readiness for seasonal susceptibilities and impending adverse weather conditions.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance for not being adequately prepared for the onset of frazil ice conditions prior to January 6, 2004, a point at which the conditions for icing of the intake crib existed.

Description: Davis-Besse Procedure DB-OP-06913, “Seasonal Plant Preparation Checklist,” described the conditions when icing of the intake crib could exist. Specifically these conditions were:

- lake temperature near freezing point;
- lake level low in the range of 569-570 feet;
- windy conditions with low air temperatures; and
- no ice cap formed on the lake.

The procedure stated that, by November 1 of each year, arrangements should be made with the Maintenance Services Department to obtain a high capacity trash pump, suction and discharge piping necessary to support pump operations and that the equipment be stored in a suitable location for future use. The purpose of the high capacity pump was to provide the ability to pump water from the lake to the intake forebay if required.

On January 6, 2004, upon observing decreasing forebay level, the resident inspectors questioned the operations staff as to whether they were monitoring forebay level and if they recognized that conditions existed that were conducive to the formation of frazil ice conditions. As a result of the inspectors’ questions, the licensee determined that the conditions for frazil ice formation in the intake crib existed and that as of January 6, 2004, no preparations for staging of the pump and hoses nor the ability to contact personnel to provide the pump and hoses on a short notice had been arranged. The licensee made arrangements to have the high capacity pump and hoses staged on January 7, 2004.

Analysis: The inspectors determined that not sufficiently coordinating and being adequately prepared for frazil conditions prior to January 6, 2004, was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” issued on June 20, 2003. The inspectors determined that the finding was more than minor because, if left uncorrected, it could contribute to the likelihood of those events that upset plant stability. Specifically, the failure to adequately prepare for frazil ice conditions could result in a plant shutdown as required by DB-OP-06913. Utilizing the Phase 1 Screening Worksheet, per Inspection Manual Chapter 0609, “Significance Determination Process,” the inspectors determined this performance deficiency impacted the Initiating Event Cornerstone because it constituted a transient initiator contributor. The inspectors answered “no” to Phase 1 Initiating Event questions because the finding: (1) was not associated with the likehood of primary or secondary system LOCA initiation; (2) did not contribute to the likelihood that mitigation systems would be unavailable; and (3) was not associated with fire or flood.

Enforcement: The Seasonal Plant Preparation Checklist was not required by 10 CFR Part 50, Appendix B; therefore, no violation of regulatory requirements occurred. This issue was considered to be a finding of very low safety significance (FIN 50-346/2004002-01). This licensee entered the event into its corrective action system as CR 04-00179.

.2 Procedure Specified Heater not Available for EDG 2 Room

a. Inspection Scope

The inspectors reviewed the licensee's response to unexpected annunciator alarm 1-1-K EDG 2 TRBL received on January 25, 2004, which was the result of decreasing temperatures in EDG 2 Room. The inspectors interviewed licensee personnel and reviewed control room logs, alarm procedures, operating procedures, and condition reports.

b. Findings

Licensee was unable to locate the necessary equipment required per the annunciator alarm response procedure to provide additional temporary heating for the room. Section 4OA5 discusses the regulatory aspects of this finding.

1R05 Fire Protection (71111.05Q)

.1 Area Inspections

a. Inspection Scope

The inspectors conducted fire protection inspections, which were focused on the availability, accessibility, and condition of fire fighting equipment, the control of transient combustibles, and the condition and operating status of installed fire barriers. The inspectors selected fire areas for inspection based on their overall contribution to internal fire risk, as documented in the Individual Plant Examination of External Events, their potential to impact equipment which could initiate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed at the end of this report, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use, that fire detectors and sprinklers were unobstructed, that transient material loading was within the analyzed limits, and that fire doors, dampers, and penetration seals appeared to be in satisfactory condition.

The following two areas were inspected:

- Fire Area R; Auxiliary Shutdown Panel And Transfer Switch Room
- Fire Area DG; No. 1 Electrical Penetration Room

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Evaluation (71111.13)

a. Inspection Scope

The inspectors reviewed the licensee's response to risk significant activities. These activities were chosen based on their potential impact on increasing overall plant risk. The inspection was conducted to verify the planning, control, and performance of the work were done in a manner to reduce overall plant risk and minimize the duration where practical, and that contingency plans were in place where appropriate. The licensee's daily configuration risk assessments, observations of shift turnover meetings, observations of daily plant status meetings, and the documents listed at the end of this report were used by the inspectors to verify that the equipment configurations had been properly listed, that protected equipment had been identified and was being controlled where appropriate, and that significant aspects of plant risk were being communicated to the necessary personnel. The following nine risk significant issues were evaluated by the inspectors:

- On January 4, 2004, the development and implementation of a problem solving plan to investigate and respond to a Reactor Coolant Pump 2-2 High Seal Return Flow alarm which, if concurrent with other indications, would indicate degrading seal performance and potentially seal failure;
- On January 6, 2004, the licensee response to problems with Auxiliary Feedwater Pump 1 governor speed increaser motor and subsequent troubleshooting of a casing steam leak. The speed increaser motor was replaced and the steam leak was initially addressed by a temporary modification (see Section 1R23);
- On January 19-22, 2004, the modification of 10 Turbine building doors due to a preliminary analysis of the effects of a Main Steam Line Break using new computer models which initially determined that these doors would not be able to withstand the initial pressure wave caused by a guillotine break of the main steam line and could subject safety related equipment to an adverse environment;
- On January 22, 2004, the replacement of the gasket for Feed Water Discharge Valve 1009 [Motor Driven Feed Pump to Main Feedwater Discharge Check] which required the securing of the Motor Driven Feedwater Pump and the use of the Startup Feedwater Pump to maintain feedwater flow to the steam generators;
- On January 26-27, 2004, the replacement of Main Steam Line 1 Isolation Valve, Solenoid Valve SV101C which required defeating Turbine Bypass Valve and Main Steam Line 1 Isolation Valve interlocks;
- On January 29, 2004, the development and implementation of a problem solving plan to investigate and respond to the reoccurrence of a casing steam leak on Auxiliary Feed Water Pump 1 observed during the performance of the AFPT 1 Quarterly Test;
- On February 2, the development and implementation of a problem solving plan to investigate and respond to the Startup Transformer X01 A Phase Bushing oil leak. The licensee removed the transformer from service and entered TS 3.8.1.1.(a) due to having one offsite circuit of A.C. Electrical power inoperable. The licensee performed a 10 CFR 50.59 evaluation to implement changes to the Davis-Besse TS Bases, Updated Safety Analysis Report (USAR), plant procedures and associated engineering analysis to allow the onsite

Class 1E AC power system to be powered from the offsite power source by a qualified circuit consisting of the Main Power Transformer backfed from the 345 kV offsite transmission system and powering the Unit Auxiliary Transformer and 13.8 kV buses from the Main Power Transformer;

- On February 7 - 8, 2004, entered an Orange risk condition with both startup transformer X02 and the 345 kV Bus K isolated to remove the Ohio-Edison Line from service to replace cotter pins missing from the clevis of eight towers outside of Sandusky, Ohio; and
- On February 13, 2004, the development and implementation of a problem solving plan to investigate and respond to Component Cooling Water Pump Room Ventilation Train 2 anomalies.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions (71111.14)

a. Inspection Scope

The inspectors reviewed the licensee's performance during planned non-routine evolutions. The inspectors attended Infrequently Performed Evolution briefs, pre-job briefs, reviewed operations evolution orders, and observed evolutions in the control room and in the field. The inspectors reviewed selected prior events to determine if they were adequately addressed to prevent recurring events, verified if the operators responded in accordance with procedures and training, and determined if the evolution was conducted in a safe and conservative manner. The following six non-routine evolutions were reviewed:

- On January 8 - 9, 2004, the inspectors observed operations personnel performance during a reactor plant cooldown from operational Mode 3 to Mode 4. This cooldown was required by TS 3.7.1.2.(a) due to the inoperability of one train of auxiliary feedwater;
- On January 22, 2004, the inspectors observed operations personnel performance during the swapping of the motor driven feedwater pump and the start-up feedwater pump to facilitate replacement of the gasket for Feed Water Discharge Valve 1009 [Motor Driven Feed Pump to Main Feedwater Discharge Check];
- On January 26, 2004, the inspectors observed control room personnel performance during the starting of Reactor Coolant Pump 1-1 during plant heat-up to normal operational temperature and pressure;
- On January 26, 2004, the inspectors observed operations personnel performance during the bypassing of Main Steam Isolation Valve MS 101 to facilitate replacement of Steam Feed Rupture Control System Solenoid Valve SV101C;
- On January 27, 2004, the inspectors observed control room personnel performance during the reactor coolant system isolation check valve leak test for Decay Heat Valves DH 76 and DH 77. The purpose of the test was to

demonstrate the operability of the Reactor Coolant system pressure isolation valves, by individually leak testing check valves DH 76 and DH 77; and

- On February 7, 2004, the inspectors reviewed the performance of the control room operators and their oversight management during the Absolute Position Indication Functional Test. The purpose of the test was to verify functionality of the Absolute Position Indication Channels of the Control Rods. The inspectors observed the Infrequently Performed Evolution briefs, the Pre Job briefs and observed evolutions in the control room and at the control rod cabinets.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed post-maintenance testing activities to ensure that the testing adequately verified system operability and functional capability with consideration of the actual maintenance performed. The inspectors used the appropriate sections of the TSs and the USAR, as well as the documents listed at the end of this report, to evaluate the scope of the maintenance and verify that the work control documents required sufficient post-maintenance testing to adequately demonstrate that the maintenance was successful and that operability was restored. The inspectors observed and evaluated test activities associated with the following four samples:

- On January 3, 2004, testing the functionality of the transfer of Auxiliary Feedwater Pump Suction, within 10 seconds, to Service Water upon loss of normal supply after the replacement of a time delay relay in the circuitry;
- On January 16, 2004, testing the Auxiliary Feedwater Pump Turbine 1 High Speed Stop and Overspeed Trip setting after repairing a pump casing steam leak;
- On January 17, 2004, testing the Auxiliary Feedwater Pump Turbine 2 High Speed Stop and Overspeed Trip setting after replacing the turbine casing seal material; and
- On January 27, 2004, stroke time testing of the Main Steam Line 1 Isolation Valve after replacement of Main Steam Line 1 Isolation Valve Solenoid Valve SOV101C.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage (71111.20)

a. Inspection Scope

The inspectors evaluated the licensee's efforts to remove loose debris from containment as required by Plant Procedure DB-OP-06900, Attachment 11, Revision 15, and TS 4.5.2.c.

On January 6, 2004, the inspectors made a containment under vessel entry with a licensee team that was doing VT-2 and boric acid inspections. The activities of the accompanied team included removing FLUS temporary instrumentation (installed under a temporary modification), placing permanent placards on I-beams, looking for any indication of leakage, and verifying that the under vessel area was free of debris and any equipment other than that designed to be in that location. The inspectors also attended the brief for entry under the reactor vessel, which was an entry into a locked high radiation area, and observed radiation work practices and use of dosimetry.

On January 19, 2004, the inspectors made a tour of the containment including the east steam generator enclosure, the incore instrument tank area, and the 565' floor elevation outside of the steam generator enclosures.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed the surveillance test and/or evaluated test data to verify that the equipment tested met TSs, USAR, and licensee procedural requirements, and also demonstrated that the equipment was capable of performing its intended safety functions. The inspectors used the documents listed at the end of this report to verify that the test met the TS frequency requirements; that the test was conducted in accordance with the procedures, including establishing the proper plant conditions and prerequisites; that the test acceptance criteria were met; and that the results of the test were properly reviewed and recorded.

The following two activities were evaluated:

- On January 28, 2004, the functional test of the auxiliary feed pump turbine 1 inlet isolation on low steam line pressure interlock; and
- On February 9, 2004, the control rod assembly insertion time test. The inspectors attended pre-activity briefs and witnessed the majority of the testing either from the control room or at the control rod drive mechanism panels.

b. Findings

No findings of significance were identified. All control rod drive mechanisms met their insertion time acceptance criteria.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed Temporary Modification 04-0002, "K3-1 Auxiliary Feedwater Pump Turbine," to verify that the modification did not affect the safety functions of this risk significant safety system. The temporary modification was a 24 gauge stainless steel deflector and the installation of a temporary material on the turbine governor cooling lines above the outboard bearing housing. The purpose of the modification was to direct moisture from a steam casing leak away from the outboard bearing housing. The inspectors reviewed the temporary modification package and associated 10 CFR 50.59 screening and compared them to system, USAR, and TS requirements to determine if there were any effects on system operability or availability and to verify temporary modification consistency with plant documentation and procedures.

b. Findings

No findings of significance were identified

1EP2 Alert and Notification System (ANS) Testing (71114.02)

a. Inspection Scope

The inspectors discussed with Emergency Preparedness (EP) staff the provisions for the operation, maintenance, and periodic testing of the ANS in the Davis-Besse Station's Emergency Planning Zone to determine whether the ANS equipment was adequately maintained and tested in accordance with Emergency Plan commitments and procedures. The inspectors reviewed records of 2002 and 2003 preventive and non-scheduled maintenance activities and a sample of 2003 ANS operability test results.

The inspectors also discussed the status of the ANS siren upgrade project, which was roughly 50 percent complete, and determined that work on this project was expected to resume in 2005.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization (ERO) Augmentation Testing (71114.03)

a. Inspection Scope

The inspectors reviewed and discussed with EP staff the procedures that included the primary and alternate methods of initiating an ERO activation to augment the onshift ERO, plus the provisions for maintaining the ERO call-out roster and for periodically updating the ERO Telephone Directory. The inspectors also reviewed critique records of semi-annual, unannounced, off-hours staff augmentation drills that were conducted in

2002 and 2003 to determine the adequacy of the drills' critiques and associated corrective actions.

The inspectors also reviewed training records of a random sample of 30 Davis-Besse Station personnel, who were assigned to key and support ERO positions, to determine whether they were currently trained for their assigned ERO positions.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

The inspectors, with NRC Headquarters assistance, performed a review of the current site-specific Emergency Action Levels (EAL), as found in Revision 3 to Emergency Plan Implementing Procedure (EPIP) RA-EP-01500, and Revision 10 to discontinued EPIP EI-1300.01 to determine whether refinements or other changes made to any EAL since 1985 may have decreased the effectiveness of the licensee's emergency planning. Applicable portions of the following were used as reference criteria: 10 CFR 50.54(q); 10 CFR 50.47(b); 10 CFR Part 50, Appendix E; Revision 1 of Nuclear Regulatory Guide (NUREG) 0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants;" and Revision 2 of the Nuclear Management and Resources Council/National Environmental Studies Project-007, "Methodology for Development of Emergency Action Levels."

The inspectors also reviewed a sample of records that provided the bases of refinements and other changes that were made to certain EALs since 1985 in response to concerns identified in 1985 and 1986 NRC Inspection Reports and various licensee self-assessments.

b. Findings

Introduction: The licensee changed one indicator of its Unusual Event EAL 5.A.1, which addressed initiation of the Steam and Feedwater Rupture Control System (SFRCS) following a rapid depressurization of the secondary side, such that this indicator only clearly addressed an automatic initiation of the SFRCS and not also a manual initiation of this system, as was clearly stated in the prior version of this EAL. The NRC determined that the change to this indicator decreased the effectiveness of the licensee's emergency plan. The licensee did not submit this change to NRC for prior approval. This is a violation of 10 CFR 50.54(q) and, because it impacted the regulatory process, traditional enforcement was applied. Since this issue was entered into the licensee's corrective action program, adequate corrective actions were completed, and because this item involved a failure to meet a regulatory requirement not directly related to assessment or notification, this issue was determined to be a Severity Level IV Non-Cited Violation (NCV).

Description: The licensee's site-specific EALs were based on the guidance of NUREG 0654, Revision 1. The EAL 5.A.1 was the site-specific interpretation of the NUREG's Unusual Event Example Initiating Condition 17, "rapid depressurization of a pressurized water reactor's secondary side." In 1988, the licensee revised one indicator of Unusual Event EAL 5.A.1 to delete words which clearly indicated that either a manual or an automatic initiation of the SFRCS on low main steam line pressure would warrant an Unusual Event declaration. The EP staff informed the inspectors that this indicator was changed due to feedback from a Control Room Simulator training session. The wording of the previous and current EALs were as follows:

Previous EAL Indicators

Increasing containment pressure (if leak is inside containment) OR unusually loud noise OR visual sighting outside containment
AND
Valid SFRCS initiation automatically or manually on low main steam line pressure

Current EAL Indicators

Increasing containment pressure (if leak is inside containment)
OR
Unusually Loud Noise
OR
Visual sighting outside containment
AND
Valid SFRCS automatic initiation on low main steam line pressure

The licensee's analysis of the revised indicator involving SFRCS initiation was that a manual initiation of the SFRCS to preclude its automatic actuation was considered to be an automatic actuation. When the EAL was revised, the licensee concluded that the above change to the indicator involving SFRCS initiation did not decrease the effectiveness of the emergency plan.

In contrast, the inspectors determined that the change to this indicator represented a decrease in effectiveness of the emergency plan because the re-worded indicator narrowed the scope of the indicator by not clearly addressing manual initiation of the SFRCS. The wording of an EAL's indicator needed to be straightforward such that any Shift Manager could make a timely and accurate decision on whether or not to declare an emergency without having to recall details from a training session or research other procedures.

The inspectors concluded that the aforementioned change to the SFRCS indicator and its technical bases should have been submitted for NRC review and approval prior to implementation of revised EAL 5.A.1. However, since the licensee had concluded in 1988 that the change to this indicator did not decrease the effectiveness of the emergency plan, this change was not submitted to the NRC for review prior to implementation of the revised indicator.

Analysis: The inspectors determined that the licensee failed to meet the requirements of 10 CFR 50.54(q) when it failed to identify a decrease in effectiveness of its standard EAL classification scheme following the 1988 revision. A standard classification and action level scheme is required by 10 CFR 50.47(b)(4). Additionally, no actual safety consequence was identified; however, the inspectors determined that the issue had a potential for impacting the NRC's ability to perform its regulatory function. Therefore, in accordance with NRC's Enforcement Policy and Appendix B of Manual Chapter 0609, traditional enforcement was applied instead of the Significance Determination Process (SDP).

Enforcement: 10 CFR 50.54(q) states, in part, that the "licensee may make changes to these plans without Commission approval only if the changes do not decrease the effectiveness of the plans. Proposed changes that decrease the effectiveness of the approved emergency plans may not be implemented without application to and approval by the Commission." In 1988, the licensee made a change to its standard EAL scheme in the EPIPs that reduced the effectiveness of the emergency plan. This change was not submitted to the NRC for approval prior to implementation in October 1988. The licensee entered this issue into their corrective action program as Condition Report (CR) 04-01475 and completed adequate corrective actions. Corrective actions included revising the affected emergency plan implementing procedure and issuing required reading packages to relevant personnel on the bases for this procedure revision.

Changing an emergency plan commitment without prior NRC approval impacts the NRC's ability to perform its regulatory function and is therefore processed through traditional enforcement, as specified in Section IV.A.3 of the Enforcement Policy, issued May 1, 2000 (65 FR 25388). According to Supplement VIII of the Enforcement Policy, this finding was determined to be a Severity Level IV because it involved a failure to meet a requirement not directly related to assessment and notification. Further, this problem was isolated to one EAL and was not indicative of a functional problem with the licensee's EAL scheme. Additionally, because the licensee entered this issue into its corrective action program (CR04-01475) and has completed adequate corrective actions, this finding is being treated as Non-Cited Violation (Severity Level IV) consistent with Section VI.A of the Enforcement Policy. (NCV 50-346/2004002-02).

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspectors reviewed those quarterly audits, which were performed during 2002 and 2003 by Nuclear Quality Assessment staff, that addressed various aspects of the EP program and a sample of resulting corrective action documents to verify that these independent assessments met the requirements of 10 CFR 50.54(t) and that adequate corrective actions were taken on identified concerns. The inspectors also reviewed a sample of critique reports and corrective action documents that were associated with the 2003 biennial exercise, as well as EP drills conducted in 2002 and 2003, to verify that the licensee fulfilled its drill commitments and to evaluate the licensee's efforts to identify, track, and resolve concerns identified during these activities. The inspectors also reviewed the EP staff's self-assessment report and a sample of related corrective action program records associated with an actual Unusual Event declaration in August 2003 due to a regional power blackout that affected offsite power supplies to the Davis-Besse Station.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

a. Inspection Scope

The inspectors reviewed the licensee's records associated with the performance indicators (PI) listed below. The inspectors verified that the licensee accurately reported the indicators in accordance with relevant procedures and Nuclear Energy Institute guidance endorsed by NRC. Specifically, the inspectors reviewed licensee records associated with PI data reported to the NRC for the period April 2003 through December 2003. Reviewed records included: procedural guidance on assessing opportunities for the three PIs; assessments of PI opportunities during pre-designated Control Room Simulator training sessions, the 2003 biennial exercise, and drills; revisions of the roster of personnel assigned to key ERO positions; and results of periodic ANS operability tests. The following PIs were reviewed:

- Alert and Notification System;
- Emergency Response Organization Drill Participation; and
- Drill and Exercise Performance.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

The inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action system at the appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Minor issues entered into the licensee's corrective action system as a result of inspectors observations are included in the list of documents reviewed which is attached to this report.

b. Findings

No findings of significance were identified.

.2 Auxiliary Feedwater Pump 1 Governor Issues

a. Inspection Scope

On September 23, 2003, and again on January 31, 2004, Auxiliary Feedwater Pump 1 failed to meet the acceptance criteria for its response time test. This issue was selected as one of the Identification and Resolution of Problems samples for further in-depth evaluation due to the potential risk significance aspect of Auxiliary Feedwater Pump 1 not being able to meet its response time. The inspectors reviewed condition reports, root cause evaluations, maintenance history, engineering analyses, previous corrective actions and other licensee documentation to ascertain the previous deficiencies identified for the response time test failures. The inspectors verified that the licensee's corrective actions for this issue included the following performance attributes:

- complete and accurate identification of the problem in a timely manner commensurate with its significance;
- evaluation and disposition of operability/reportability issues;
- consideration of extent of condition, generic implications, common cause, and previous occurrences;
- classification and prioritization of the resolution of the problem commensurate with its safety significance;
- identification of corrective actions which are appropriately focused to correct the problem; and
- completion of corrective actions in a timely manner commensurate with the safety significance of the issue.

b. Findings and Observations

There were no findings identified associated with the reviewed deficiencies; however, the licensee investigation of the most recent response time test failure was ongoing. In response to the failure on January 31, 2004, the licensee replaced the governor on AFPT 1, and the overall response time test results for the new governor were within specifications.

.3 Operations Root Cause Corrective Actions

a. Inspection Scope

On January 6, 2004, during the performance of DB-MI-03204, Channel Functional Test and Calibration of SFRCS Actuation Channel 2 Steam Generator Differential Pressure Inputs, the licensee did not perform Action Statement 16 of TS 3.3.2.2 [see Section 4OA5]. As a result of the missed TS action statement, the licensee conducted a root cause investigation (CR 04-00181) to determine why the organization's administrative controls did not exhibit the appropriate level of rigor and formality towards the adherence to licensed conditions. The licensee attributed the root cause of the event to: (1) less than adequate implementation of work practices, and (2) less than adequate implementation of managerial methods. The inspectors evaluated CR 04-00181 and its associated corrective actions as one of the Identification and Resolution of Problems samples for further in-depth evaluation.

The inspectors reviewed the condition report to ensure that:

- the full extent of the condition, generic implications, common cause and previous occurrences were considered;
- the issues were properly classified and prioritized;
- the root causes and contributing causes were identified;
- the corrective actions were appropriately focused to correct the problem;
- the corrective actions were completed within a timely manner; and
- the effectiveness of previous actions designed to correct similar events were considered.

The licensee concluded that the causes and contributing factors for inconsistent crew performance could only be addressed through continual involvement of station management's monitoring, coaching, feedback and correction. As a result, Operations management developed a series of corrective actions that were to be completed prior to entry to Mode 3 or prior to reactor startup. Any remaining items were considered long term actions. The inspectors verified the licensee's Mode 3 corrective actions had been implemented during periods of continuous control room observation from January 1 to January 5, 2004, January 8 to January 9, 2004, and January 26 to January 28, 2004. Specifically, the inspectors verified that:

- formal peer checks of TS entries were being performed by a second licensed individual;
- formal peer checks were being logged in the narrative log;
- reactor operators were co-authorizing the start of maintenance instructions that affected TS equipment;
- reactor operators were tracking short duration TS actions using an electronic timer;
- that "Crew Updates" to keep the crew informed of significant changes in plant status were being performed during transient conditions and normal plant operations; and
- the Operations Superintendent and Operations Manager were spending a portion of each day monitoring and mentoring shift personnel.

b. Findings and Observations

There were no findings identified. The inspectors verified that the licensee had an appropriate schedule for the implementation of the remaining corrective actions.

.4 (Closed) URI 05000346/2002014-06: Question Regarding Licensee Compliance with Code Relief Valve Requirements.

During November of 2002, the NRC identified a concern for potentially inadequate over-pressure protection for the containment air coolers (CACs), decay heat removal

(DHR) coolers, emergency diesel generator jacket water (EDGJW) heat exchangers and associated system piping. For example, the NRC had questioned the use of locked open valves between the relief valve and the Code components requiring relief protection with respect to meeting the American Society of Mechanical Engineers (ASME) Code requirements for positive controls and interlocks on stop valves.

On January 23, 2004, the inspectors completed an on-site inspection of this concern focused on the location of the system relief valves to ensure over-pressure protection was provided for the CACs, EDGJW heat exchangers and DHR coolers under operating/design basis conditions. The inspectors discussed the specific requirements and system configurations associated with over-pressure protection with NRC staff in the Office of Nuclear Reactor Regulation and no concerns for Code compliance were identified. Specifically, the inspectors confirmed that:

- The EDGJW coolers and CACs were not Code stamped vessels and thus did not have component level design requirements governing over-pressure protection. The over-pressure protection for the CACs was provided by pressure relief devices for the service water system in which the CACs were installed.

- The DHR coolers were Code stamped vessels, which had component level over-pressure protection requirements from the original design Code (ASME Code, Section III and Section VIII, 1968 Edition). The inspectors confirmed that the configuration and location of the system over-pressure protection devices was consistent with these requirements.

- For the component cooling water, service water and decay heat removal piping systems which contained these components, the applicable design Code was the ASME Code, Section III, 1971 Edition. This design Code contained specific requirements associated with the location, capacity and types of relief protection required. The inspectors confirmed that the configuration and location of the system over-pressure protection devices were consistent with these requirements for the piping sections containing these components.

For these systems and components, the licensee had not produced a written document that explicitly identified how the applicable over-pressure protection requirements from the design Codes were implemented. The inspectors were concerned that without an explicit written over-pressure protection record, changes in plant operating lineups or system components could render the Code over-pressure protection strategy ineffective and result in damaged equipment. Based upon this observation, the licensee implemented corrective actions (CR 04-00582) to document the over-pressure protection strategy for these systems and components in controlled safety-related calculations.

The inspectors did not identify any normal or emergency operating system configurations or lineups that would result in isolating the CACs, EDG JW coolers and DHR coolers from over-pressure protection devices, without considering these components and associated piping systems inoperable. Further, no deviations from applicable Code requirements were identified with respect to location of relief protection devices for these components. This URI is closed.

.5 (Closed) AV 05000346/2003021-01: Potential Inability for HPI Pumps to Perform Safety Related Function

This issue is discussed in this report under closure of LER 05000346/2003-002-01. The NRC's review of the information provided by the licensee and final determination of significance (White), is documented in NRC Inspection Report 05000346/2004005, which was issued on March 5, 2004.

.6 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

From September 8, 2003, through October 10, 2003, and December 16, 2003, in the Region III Office, the inspectors performed a review of condition reports associated with LER 50-346/03-001-00/01/02. The inspectors reviewed these reports to confirm that the licensee had appropriately described the scope of the problems. Additionally, the inspectors' review included confirmation that the licensee had an appropriate threshold for identifying issues and had implemented effective corrective actions. The inspectors performed these reviews to ensure compliance with 10 CFR Part 50 Appendix B, Criterion XVI "Corrective Action," requirements. The specific corrective action documents that were reviewed by the inspectors are listed in the attachment to this report.

b. Findings

Introduction: The inspectors identified a Non-Cited Violation (NCV) of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," having very low safety significance (Green) for the licensee's failure to determine the cause and implement actions to prevent recurrence for the inadequate design changes made to service water (SW) valves SW1424, SW1429 and SW1434.

Description: In LER 50-346/03-001, the licensee identified that under a loss of instrument air (LOIA), the SW system valves temperature control valves (SW1424, SW1429 and SW1434) used to throttle SW flow through the component cooling water (CCW) heat exchangers would not reach their design (full open) position. The licensee implemented corrective actions to restore the design function of these valves as discussed in Section 4OA3 of this report. The inspectors identified that the licensee had incorrectly determined that these inoperable SW valves did not represent a significant condition adverse to quality in CR 03-04158.

The licensee initially screened CR 03-04158, which documented the inoperable air operated valves (AOVs) SW1424, SW1429 and SW1434 as a significant condition adverse to quality. Subsequently, the licensee downgraded this CR to a "fix" only (category CF), which did not require determining the causes of this condition. The licensee based this decision on the assumption that the causes for these SW AOV deficiencies was the same as that found for inoperable AOVs MU66A-D and MU38 documented in CR 02-02494 and CR 02-02254. For valves MU66A-D and MU38, the licensee had identified root causes which included, a lack of design basis information and calculations to support orientation, set-up, and sizing of air operated valves during original plant construction. However, for valves SW1424, SW1429 and SW1434, the licensee had removed air accumulators for the valve actuators in 1991 under modification 87-1351, which rendered these valves incapable of reaching their design open condition with a LOIA. The inspectors noted that the licensee's modification process included additional barriers such as detailed design reviews and post modification testing to confirm the design functions of these valves. The inspectors concluded that the inadequate SW modification, represented a separate and distinct significant condition adverse to quality from that found for other AOVs, because the CCW and SW systems were rendered inoperable by the inadequate implementation of the modification process. Because the licensee had not correctly classified CR 03-04158 as a significant condition adverse to quality, a root cause investigation was not performed and consequently the cause(s) for the inadequate modification were not known. Therefore, the inspectors were concerned that the licensee had not implemented corrective actions to fix the modification process errors that had resulted in the inadequately designed SW valve modifications. Although the licensee had implemented corrective measures for the SW valve design deficiencies, the licensee failed to recognize the need for a root cause investigation and to take preventative actions for the inadequate modification process until questioned by the NRC inspectors.

Analysis: The performance deficiency associated with this event, is the failure of the licensee to identify the cause(s) and implement action(s) to prevent recurrence for the inadequate SW modification 87-1351. The inspectors concluded that the finding was greater than minor in accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspections Reports," Appendix B, "Issue Disposition Screening." The inspectors concluded that the issue was more than minor; because if left uncorrected, the inadequate modification process controls could potentially result in other inoperable safety related equipment or systems. The finding was assigned to the Mitigating Systems Cornerstone because the specific example of inadequate modification process controls was associated with the SW and CCW mitigating systems. The finding also affected the cross-cutting area of Problem Identification and Resolution because although the deficient modification 87-1351 was discovered by the licensee's staff, it was not adequately resolved until questioned by the NRC inspectors. The inspectors determined that the finding could not be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, "Significance Determination Process," because the SDP for the Mitigating Systems Cornerstone only applied to a degraded systems/components, not to the process failures that could result in degraded systems/components. Therefore, this finding was reviewed by the Regional Branch Chief in accordance with IMC 0612, Section 05.04c, who agreed with the inspectors that this finding was of very low safety significance (Green), because the licensee had taken actions to restore the air operated SW valves to an operable configuration and, after identification by the inspectors, the licensee entered the failure to identify the cause(s) and implement action(s) to prevent recurrence for the inadequate SW modification 87-1351 into the corrective action program (CR 03-07859).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The inspectors considered the inadequate SW modification 87-1351 a significant condition adverse to quality, because it rendered the component cooling water and service water systems incapable of meeting their design functions under accident conditions. Contrary to the above, as of October 9, 2003, the licensee had failed to determine the causes and implement corrective action to preclude repetition for the inadequate SW modification 87-1351 installed in 1991. This issue was not an immediate concern, because the licensee implemented corrective actions to correct the specific design deficiencies in these valves as discussed in Section 4OA3. Because of the very low safety significance, and because this issue was entered into the licensee's corrective action program, this violation is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-346/04-02-03). The licensee entered this issue into the corrective action program in CR 03-07859.

4OA3 Event Followup (71153)

.1 (Closed) LER 05000346/2003-002, Revision 00 and 01: Potential Degradation of High Pressure Injection Pumps Due to Debris in Emergency Sump Fluid Post Accident

On October 22, 2002, with the reactor defueled, the licensee identified a deficiency regarding the internal clearances of the HPI pumps' ability to pass debris or particles that may be entrained in the process fluid during some post accident scenarios. Specifically, it was determined that the pump's internal openings that supplied lubricating water flow to the hydrostatic bearing were smaller than the ECCS sump screen openings. Certain reactor accident scenarios required the HPI pump (via the low pressure injection pump) to pump water that had collected in the containment ECCS sump and inject it back into the reactor coolant system (recirculation mode). It was during this mode of operation that the potential existed for debris from the sump to be transported to the HPI pump and cause blockage of lubricating water to the hydrostatic bearing.

The licensee performed extensive analysis, pump modifications, qualification testing, in-plant testing, and reduction of fibrous insulation in containment to ensure adequate HPI pump performance during the recirculation mode. The NRR staff from the Division of Engineering, Mechanical and Civil Engineering Branch and the Division of Systems Safety and Analysis, Plant Systems Branch performed a review of the analysis, testing and modifications performed by the licensee and concluded that the licensee's overall approach to the modification of the high pressure injection pumps is acceptable and provided reasonable assurance that they will perform their required functions when called upon. This review is detailed in Task Interface Agreement (TIA) 2003-04 response dated February 11, 2004, and is included as an attachment to this report.

With respect to prior plant operation with the potential to degrade the HPI pumps during the recirculation mode of operation post accident, the licensee provided a response to NRC Inspection Report 05000346/2003021 on December 5, 2003. This inspection report had determined that the preliminary significance of this issue was greater than Green. The NRC's review of the information provided by the licensee and final determination of significance (White) is documented in NRC Inspection Report 05000346/2004005. This LER is closed.

.2 (Closed) Licensee Event Report (LER) 50-346/03-001, Revisions 00, 01, and 02: Potential Inability of Air-Operated Valves to Function During Design Basis Conditions

a. Inspection Scope

From September 8, 2003, through October 10, 2003, and from February 23, 2004, through February 26, 2004, the inspectors reviewed LER 2003-001, which documented that several AOVs were not capable of performing their designated safety functions for all required conditions. The inspectors also reviewed corrective actions documented in condition reports, and design information (including calculations) associated with two AOVs (CC1467 and CC1469 - decay heat removal heat exchanger outlet valves) which were removed from this LER in subsequent LER revisions.

b. Findings

Description: On January 30, 2002, with the reactor defueled, the licensee identified that several AOVs had negative operating margins and subsequently determined that eight valves were not capable of performing their safety functions for all required conditions. On March 31, 2003, the licensee submitted a 10 CFR 50.73 report documenting this condition as an operation or condition prohibited by the Technical Specifications 3.7.3.1, 3.7.4.1 and 3.6.3.1.

On August 18, 2003, and November 26, 2003, the licensee issued Revision 1 and Revision 2, respectively to this report to update the report and to document the risk evaluation of this condition. The licensee described the causes for the inoperable AOVs as discussed below.

Valve MU3 is an air operated isolation valve which is normally open to allow letdown flow to pass from the letdown coolers to the purification demineralizers. With LOIA, this valve is designed to fail closed. However, the licensee identified that with LOIA, the spring force alone was not sufficient to close valve MU3 against maximum reactor coolant system differential pressure. The licensee implemented engineering change request (ECR) 03-0111-00 to replace the valve actuator with a new larger piston actuator and nitrogen bottles which would ensure this valve shuts with design differential pressure (CR 03-01040).

For the degraded capability of valve MU3 to close, the licensee determined that spring relaxation was not recognized by plant personnel for preventative maintenance purposes.

Valve CC 1495 is an AOV which is normally open to provide cooling water to non-essential components such as the spent fuel pool heat exchangers or reactor coolant pump seal return coolers. This valve is designed to close on a safety features actuation system (SFAS) Level 3 signal or a low level in the CCW surge tank. However, the licensee identified that upon LOIA, the air accumulator was undersized and would not ensure that the valve would fully close. The licensee implemented ECR 03-0136-00 to install a larger air accumulator associated with the actuator for valve CC 1495 (CR 03-01253).

The licensee attributed the apparent cause of the valve CC 1495 deficiencies to original procurement practices that resulted in obtaining an undersized air accumulator. The licensee identified that the air operated valve vendors had been being supplied with inaccurate system information and had used less than conservative sizing methodologies.

SW system isolation valves SW1356, SW1357, and SW1358, are normally open to provide a flow path for SW to the containment air coolers (CACs). During normal and emergency operation, two of the three CACs are in service and the remaining CAC will have its SW isolation valve closed to support containment isolation. However, with LOIA, the air accumulators for these valves did not have sufficient capacity to hold the valves shut for up to 30 days to support containment isolation. The licensee implemented ECR 02-0836 to install larger air accumulators (CR 02-07781).

The licensee attributed the valve SW1356, SW1357, and SW1358 deficiencies to a lack of understanding (during original plant construction) of the plant's design and licensing basis and a failure to correlate this information into the design of the accumulators for these valves.

SW system valves SW1424, SW1429 and SW1434 are temperature control valves used to throttle SW flow through the CCW heat exchangers. During emergency operation, these valves go to their full open position upon receipt of an SFAS Level 2 signal to maximize SW flow through the CCW heat exchangers. These valves are required to fail open upon LOIA. These valves have spring air cylinder actuators which require the presence of air to position the valve. Upon LOIA, the licensee identified that these valves would not fully open. The licensee performed a dynamic differential pressure test (without instrument air) for valve SW1434, and this valve opened to 28 degrees from fully shut and stalled in this position. The licensee initiated ECR 03-0299-00 to install an air accumulator for each valve to ensure the motive air force exists for valve operation under accident conditions (CR 03-04158). The licensee identified in this LER that they had made an incorrect engineering assumption in the design of the actuators for these valves when the original air accumulators were removed and actuators replaced in 1991 (modification 87-1315). The inspectors identified that the licensee had not correctly classified this condition as a significant condition adverse to quality and identified root causes as discussed in Section 4OA2.

The licensee implemented the corrective actions for each of the inoperable valves as stated above to restore these systems to an operable condition. In the original version of LER-03-001, the licensee had identified that the decay heat removal heat exchanger outlet valves CC1467 and CC1469 were not operable because of undersized operators. The licensee subsequently determined that these valves were operable based upon a revised calculation C-ME-016.04-035, "Component Level Review Calc for AOV CC1467/1469," which demonstrated that these valves had adequate operating margins with the existing accumulators. The inspectors reviewed calculation C-ME-016.04-035 and C-ME-016.04-031, "Maximum Expected Differential Pressure For Valves CC-1467 and CC-1469," to confirm that the licensee had used industry accepted methodologies to demonstrate that sufficient operating margins (e.g. to account for uncertainties) existed for these valves. Because the licensee intended to apply the same approach to demonstrate operating margins for each of the modified AOVs, the inspectors did not identify any operability concerns for the modified AOVs.

Analysis: The licensee documented the risk for the degraded AOVs as discussed below.

- For valve MU3, the licensee determined that the valve would have functioned to isolate letdown flow under the reduced differential pressure which would exist under accident conditions. Additionally, a motor operated valve MU2A existed which was fully functional and would have isolated letdown flow under accident conditions.

- For valve CC1495, the licensee determined that the valve would not have fully closed to isolate nonessential component cooling water loads. However, motor operated valves CC5096 and CC5097 were fully functional and would have automatically isolated the nonessential cooling loads on a low CCW surge tank level.

- The licensee determined that valves SW1356, SW1357, and SW1358, would not have been capable of maintaining containment isolation capability. Because this SW piping is a closed fluid filled system inside containment the licensee determined that this condition would not create a release pathway for post-accident radioactive material.

- The licensee determined that SW1424, SW1429 and SW1434, would not have been capable of stroking to their full open position upon receipt of an SFAS Level 2 signal with loss of instrument air. This degraded SW flow condition was evaluated as part of the licensee's risk evaluation and determined to have minimal safety significance.

The licensee also performed a calculation to determine the increase in core damage frequency, core damage probability, large early release frequency and large early release probability due to the condition described in LER 2003-001. Based upon the results of this calculation, the licensee determined that these valve conditions were considered to have minimal safety significance. The licensee's calculation and risk evaluation were reviewed by the inspectors and a Region III Senior Reactor Analyst (SRA).

Although a number of AOVs were affected, the inspectors determined that the degraded CCW heat exchanger service water outlet valves SW1424, SW1429, and SW1434 posed the most significant challenge to risk. For these valves, the licensee had removed the air accumulators that assist in valve stroking, and then determined through a dynamic differential pressure test performed on SW1434, that the spring operator force alone was not adequate to fully open the valve. The failure position of these valves during a LOIA initiating event was potentially insufficient to assure adequate SW cooling through the decay heat coolers to support cooling of safety related equipment needed to mitigate a loss of coolant accident (LOCA). Specifically, the heat loads on the CCW system, could exceed the reduced cooling capacity of the decay heat coolers when sump recirculation is initiated after depletion of the borated water storage tank (BWST) inventory following a LOCA.

The inspectors determined that this issue was more than minor because it affected the ability of mitigating systems to perform their function during certain accident scenarios (e.g. mitigating systems cornerstone objective was challenged). Because this issue represented an actual loss of a safety function of a system, the inspectors performed a Phase 2 risk screening using the Davis-Besse site-specific SDP worksheets. The inspectors concluded that the LOIA was the only initiating event where a potential for a significant contribution to core damage frequency (CDF) occurs, because a reactor coolant pump (RCP) seal LOCA can be caused by a LOIA. For a RCP seal LOCA (very small LOCA), the licensee's calculations determined that the time required to empty the BWST was approximately 15 hours. For this sequence, the licensee determined that prior to the depletion of the BWST, the heat load from the decay heat coolers would not be imposed on the CCW system. Therefore, the licensee concluded that the CCW system cooling was adequate for the injection phase on a RCP seal LOCA, and ample time was available for operator action to fully restore CCW cooling by fully opening the SW outlet valves (per existing procedures).

For the Phase 2 evaluation of this issue, the inspectors only considered cutsets involving high pressure recirculation because of the long period of time before BWST depletion. Using the LOIA worksheet and considering the two high pressure recirculation sequences with 1 point credit (10^{-1}) for operator recovery, the inspectors determined that the resulting risk (change in CDF) was 10^{-5}. The inspectors considered that this risk estimate was very conservative due to the ample time (15 hours) that operators would have to recover the full capability of the CCW heat exchangers by fully opening the SW outlet valves.

A Region III SRA completed a Phase 3 risk evaluation focused on the recovery credit for restoration of CCW under the conditions discussed above. The Region III SRA reviewed the licensee's human reliability analysis (HRA) for this evolution and also performed an independent HRA calculation with the methodology utilized in the SPAR model. When an SFAS Level 2 signal is received following the initiation of a LOCA, the operators are required to verify the status of the SW valves to the CCW heat exchanger. Indications available to the operators include the indicating light for this valve which for this scenario, would have been off, instead of lit. With insufficient SW flow, the CCW heat exchanger outlet temperature alarm would have come in at 115°F, which would require an operator to implement procedure DB-OP-02523, "Component Cooling Water System Malfunctions," and take actions to restore the system. Even though the BWST would not be depleted until 15 hours, the licensee assumed that the SW valves would need to be opened within 1 hour. The SRA agreed with this conservatism. The SRA used the SPAR model human error worksheet for recovery of the CCW system with the following assumptions: 1) the operators would have had more than enough time to restore the CCW system; and 2) stress, complexity, experience, procedures, fitness for duty, and work processes were set to the nominal value. This resulted in a CCW system non-recovery probability of 10^{-3}, or 3 points in the SDP LOIA worksheet. With the more realistic credit given for operator action, the SDP worksheets indicated that the risk characterization was 7 (10^{-7}) or Green. Because the CCW system does not provide cooling to important containment cooling systems, including the CACs and containment spray systems, the SRA determined that this issue did not play an important role in the large early release frequency and would not cause the risk to rise above the Green threshold. Therefore, the SRA determined that this issue is characterized as having very low risk significance.

Enforcement: This licensee-identified finding involved a violation of TS 3.7.3.1 (CCW system was required to be operable), TS 3.7.4.1 (SW system was required to be operable), and TS 3.6.3.1(containment isolation valves were required to be operable). However, based upon calculations performed by the licensee for the degraded CCW system performance and the availability of redundant safety equipment (e.g. other motor operated valves), the violations of TS 3.7.3.1, TS 3.7.4.1 and TS 3.6.3.1 are not more than very low safety significance. Therefore, the inspectors determined that this licensee-identified finding met the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs. This finding was determined to be of very low safety significance and is dispositioned in Section 4OA7 of this report. This LER is closed.

.3 (Closed) Licensee Event Report (LER) 50-346/2003-05; Revisions 00 and 01: Containment Gas Analyzer Heat Exchanger Valves Found Closed Rendering the Containment Gas Analyzer Inoperable.

The licensee's initial submittal of this LER discussed a condition where the component cooling water isolation valves on the inlet and outlet to the heat exchangers located in each of the two Containment Gas Analyzers Systems (CGAS) were found stuck shut. This resulted in the CGAS being inoperable. This issue was evaluated by the inspectors and documented in Inspection Report 50-346/03-017.

Supplement 01 to this LER, dated January 23, 2004, described the following two additional issues that were identified by the licensee during the extent of condition evaluation, that directly impacted the proper operation of the hydrogen gas analyzers:

- The instrument air supplied to the moisture trap drain check valve associated with the hydrogen analyzer's heat exchanger was non-safety grade. Post accident, no credit can be taken for this air supply. Therefore, the drain valve is assumed to not have functioned. Additionally, the regulator which supplied the air to the drain valve was set too low for the drain valve to operate as designed.
- The moisture trap's potentially contaminated condensate, via the drain valve, would flow to a floor drain in a room not served by the emergency ventilation system. This constituted a potential containment bypass pathway.

The licensee addressed the first issue by eliminating the reliance of the drain check valve on instrument air by replacing the air operated drain valves with solenoid operated valves, powered by independent essential power sources. The second issue was corrected by routing the potentially contaminated condensate to an existing ECCS floor drain.

The inspectors determined that the improper application of non-safety related instrument air to the containment gas analyzers was a licensee identified violation of 10 CFR 50, Appendix B, Criterion III, "Design Control." This finding is unrelated to SSCs that are needed to prevent accidents from leading to core damage. To determine if this finding had an effect on large early release frequency (LERF), the inspectors used MC 0609, "Significance Determination Process," Appendix H, Containment SDP. The finding is characterized as a Type B finding (having no impact on core damage frequency (CDF)) and compared to Table 3 in Appendix H. The inspectors determined that the hydrogen analyzer had no impact on the containment-related SSCs listed in Table 3 (i.e. containment penetration seals, containment isolation valves or purge and vent lines) and would not influence LERF. Based on this, the finding has very low safety significance.

The inspectors determined that the potential containment bypass pathway caused by the improper trap condensate drain path was a licensee identified minor violation of 10 CFR 50, Appendix B, Criterion III, “Design Control.” This issue was determined to be of minor significance because there was no evidence that the trap had ever functioned, and since the air supplied to the trap was of insufficient pressure for operation of the trap, it was highly unlikely that the trap would have ever functioned.

Based on the inspectors’ review of the LER and the licensee’s corrective actions to address the design deficiencies, this LER is closed.

.4 <u>(Closed) Licensee Event Report (LER) 50-346/2003-006:</u> Potential Errors in Analysis of Block Walls Regarding HELB Differential Pressure and Seismic Events

This event report documented that on May 21, 2003, the licensee, while reviewing their existing structural analyses for walls within the Auxiliary Building, identified via calculation, that masonry Wall 2257 would not remain operable when subjected to compartment pressurization loads from a high energy line break (HELB) concurrent with loads from a design seismic event. Wall 2257 forms the boundary between Room 241 (a passageway on the 565 foot elevation of the Auxiliary Building) and Room 240 (Boric Acid Addition Tanks). The licensee has determined that failure of the block wall could adversely affect Component Cooling Water Auxiliaries Return Isolation Valves, a Service Water supply line to Containment Air Cooler 1, and the functioning of Boric Acid Addition equipment within Room 240.

The licensee has determined that the structural analyses done in the 1980's in response to Generic Letter 80-11 [Masonry Wall Design] incorrectly modeled that a high energy line break in a room adjacent to Room 241 would not impact Room 241, although the rooms are open to each other. The licensee determined the misapplication of the HELB model was a result of a lack of communication between design engineering groups performing different sets of calculations and inadequate development and maintenance of calculations in the 1980s.

In August 2003, the licensee modified a door to Room 240 so that, in the event of differential pressure across the wall and door, as would be seen with a postulated HELB, the door would open to reduce differential pressure across Wall 2257. This venting of pressure by the door reduced the calculated loads on Wall 2257 during a HELB and concurrent seismic event and the wall would remain operable.

The inspectors determined that failure to provide measures for controlling design interfaces and for coordination among participating design organizations was a licensee identified violation of 10 CFR 50, Appendix B, Criterion III, “Design Control.” This issue was determined to be of more than minor significance because the calculation errors were significant enough that a modification was required to resolve the wall loading issues. The finding affects the Mitigation Systems Cornerstone and was considered to have a very low safety significance (Green) using Appendix A, Attachment 1 of the Significance Determination Process because the event does not involve the total loss of any safety function as identified by the licensee. This issue was discussed further in Section 4OA7 of this report.

Based on the inspectors’ review of the LER, a physical review of the modification and location of equipment within Room 280, and a review of the licensee’s corrective actions including the Root Cause for the event, this LER is closed.

.5 <u>(Closed) Licensee Event Report (LER) 50-346/2003-013</u>: Unplanned Reactor Trip Condition with the Reactor Shutdown

On September 30, 2003, with the plant in Mode 3, following the completion of a normal operating pressure test using non-nuclear heat, an unplanned reactor trip occurred due to a valid Shutdown Bypass High Pressure signal. This signal inserted control rod Group 1 while the operators were performing a plant cooldown. The Reactor Protection System and all components responded as intended. There were no post-trip response equipment issues identified. The licensee attributed the reactor trip to less than adequate operator performance, procedural guidance, and pre-job brief. Corrective actions included: providing more prescriptive guidance in the plant shutdown and cooldown procedure, the incorporation of a requirement to conduct a pre-job brief which include specific operating experience gained from this event, discussion of the event with on-shift operating personnel, developing a case study of the event for initial and continuing training, and developing an Operations Improvement Action Plan. The licensee documented the unplanned reactor trip in CR 03-08374. A Non-Cited Violation for this issue was discussed in Inspection Report 05000346/2003022 (NCV 05000346/2003022-01). The LER was reviewed by the inspectors and no additional findings of significance were identified. This LER is closed.

.6 <u>Turbine Building Door High Energy Line Break Non-Emergency Report</u>

a. <u>Inspection Scope</u>

On January 19, 2004, the licensee reported, in accordance with 10 CFR 50.72(b)(3)(ii)(B), a design issue associated with the capabilities of certain turbine building doors. The licensee discovered that certain doors may not be able to withstand the initial pressure wave caused by a guillotine break of a main steam line in the turbine building. The licensee’s preliminary analysis indicated that the initial pressure wave could cause the failure of the doors leading to both trains of low voltage switchgear, and the resultant steam environment could potentially render all low voltage AC equipment and station batteries inoperable.

The inspectors evaluated the impact of this design issue on the current plant conditions, and the licensee plans to re-enforce 10 turbine building doors prior to exceeding steam pressures that could potentially challenge the existing door structures. This issue was entered into the licensee's corrective action program (CR 04-00402, 04-00442, 04-00478, and 04-00512).

b. Findings

No findings of significance were identified. Adequacy of corrective actions, impact of past system inoperability, and potential enforcement actions for the design deficiency were planned to be assessed subsequent to the licensee's LER submittal.

4OA5 Other Activities

A. Evaluation of Restart Issues

One of the key building blocks in the licensee's Return to Service Plan was the Management and Human Performance Excellence Plan. The purpose of this plan was to address the fact that "management ineffectively implemented processes, and thus failed to detect and address plant problems as opportunities arose." The primary management contributors to this failure were grouped into the following areas:

- Nuclear Safety Culture;
- Management/Personnel Development;
- Standards and Decision-Making;
- Oversight and Assessments; and
- Program/Corrective Action/Procedure Compliance.

The inspectors had the opportunity to observe the day-to-day implementation that the licensee made toward completing Return to Service Plan activities. Almost every inspection activity performed by the resident inspectors touched upon one of those five areas. Observations made by the resident inspectors were routinely discussed with the Davis-Besse Oversight Panel members and were used, in part, to gauge licensee's efforts to improve their performance in these areas on a day-to-day basis.

To better facilitate the inspection and documentation of issues not specifically covered by existing inspection procedures, but important to the evaluation of the licensee's readiness for restart, the Special Inspection for Residents inspection plan was developed and implemented. Inspection Procedure 93812, "Special Inspection," was used as a guideline to document these issues and remains in effect for future resident inspection reports until a time to be determined by the Davis-Besse Oversight Panel. The inspectors performed inspections, as required, to adequately assess licensee performance and readiness for restart in the following areas:

- performance of plant activities, including maintenance activities;
- follow-up of specific Oversight Panel Technical issues;
- licensee performance during restart readiness meetings;
- licensee performance in categorizing, classifying, and correcting deficient plant conditions during the restart process;

- licensee performance at meetings associated with work backlogs, including the deferral of work orders, operator workarounds, temporary modifications, and permanent modifications; and
- activities associated with safety conscious work environment and safety culture.

The following issues were evaluated during this inspection period.

.1 Observation of Licensee Performance During Plant Heatup and Cooldown

a. Scope

The inspectors continuously observed operation department personnel performance significant operations evolutions. The inspectors focused on control room observations, but also included evaluation of shift turnovers, scheduling meetings, pre-job briefs, and plant lineups. Observations, while primarily in the control room, included tours of the auxiliary building and containment and attendance at scheduled planning and trouble shooting meetings. Time periods of continuous observations included:

- January 2 through January 5, 2004, [completion of plant heatup to normal operating pressure];
- January 8, 2004, [plant cooldown to Mode 4 to repair an auxiliary feedwater pump]; and
- January 26 through January 28, 2004, [plant heatup to normal operating pressure and temperature].

b. Observations

The inspectors had the following observations:

- alarm response procedure usage had improved and was more consistent;
- mode constraints were properly addressed prior to applicable Mode ascension;
- pre-job briefings were appropriately detailed and the licensee effectively utilized reverse briefing techniques during pre-evolution briefs;
- licensee response to developing equipment issues was observed to be appropriate;
- operations department personnel received appropriate technical support to follow and investigate emergent equipment issues; and
- emergent equipment issues were properly investigated using formal licensee processes.

c. Conclusions

The inspectors identified no findings of significance. These examples illustrated improved performance by Operations in the areas observed.

.2 Non-Compliance with TS Action Statement

a. Inspection Scope

The inspectors reviewed licensee response to an error in maintaining control of the status of a Steam Feedwater Rupture Control System (SFRCS) steam generator differential pressure switch which resulted in an inadvertent non-compliance with a TS action statement.

b. Findings

Introduction: A Non-Cited Violation of TSs, having very low safety significance was self-revealed when, during performance of a functional test on the Steam Feedwater Rupture Control System (SFRCS) steam generator differential pressure switch, the licensee isolated the pressure switch and maintained that isolation for a period of approximately 2 hours and 24 minutes without the control room personnel knowing that the pressure switch was isolated for more than 1 hour. This rendered the pressure switch incapable of sensing differential pressure and providing a signal, if needed, to the SFRCS actuation channel 2. Failure to maintain the proper status of TS equipment was a violation of plant procedures required by TS 6.8.1., “Procedures and Programs.”

Description: On January 6, 2004, while in Mode 3, the licensee was performing a Channel Functional Test of Steam Feedwater Rupture Control System Channel 4 Steam Generator Differential Pressure Switch for Steam Generator 2 per DB-MI-0324. Channel 4 provides an input to SFRCS actuation channel 2. As required by the procedure the switch was isolated and an entry noting the removal from service at 1621 hours was made in the Unit Log. The Unit Log entry stated that “ entered T.S. 3.3.2.2 action 16 . . . .” Action statement 16 of that specification requires that action be taken within 1 hour to place the inoperable channel in a tripped condition or return the switch to service. However, the technicians performing the test determined that leaking isolation valves precluded them from performing the functional test. The technicians left the pressure switch isolated and started discussions on appropriate further action. Those discussions included work group supervisors and operations personnel. Those discussions did include the need to restore the pressure switch, but time frame for action was not made clear. At approximately 1845 hours, the pressure switch was returned to service. For approximately 2 hours and 24 minutes, the pressure switch was isolated and would not perform its function and the associated instrument channel was not placed into a tripped condition.

Analysis: The finding was determined to be more than minor in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Disposition Screening,” issued on April 29, 2002. The finding: (1) involved the configuration control and human performance attributes of the Mitigating Systems Cornerstone; and (2) affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

In accordance with IMC 0609, “Significance Determination Process,” Appendix A, Attachment 1, dated March 18, 2002, the inspectors performed an SDP Phase 1 screening and determined that the issue affected the Mitigation Systems Cornerstone in that SFRCS is used to ensure sufficient removal of core decay heat in the event of various accident conditions including a steam generator rupture. This finding was of very low safety significance because at the time of the occurrence, the reactor was in Mode 3 with no substantial decay heat and one complete actuation train of SFRCS remained operable.

Enforcement: The inspectors concluded that this is a performance issue because maintaining knowledge of system configuration and ensuring control of system configuration was reasonably within the licensee's ability to control and the event could have been prevented. The performance deficiency associated with this event is the control room staff did not adequately monitor and control system status which resulted in an unanticipated entry into a TS action statement requirement. Technical Specification 6.8.1.a requires implementation of procedures recommended by Regulatory Guide 1.33. Regulatory Guide 1.33 lists Administrative Procedures which address authorities and responsibilities for safe operation and shutdown. The licensee developed DB-OP-00000, "Conduct of Operations," Revision 07, a safety-related procedure, to, in part, provide guidance on how Operations personnel carry out their duties and responsibilities as delineated in Station Procedures, Policies, Directives, and Manuals. Step 6.2.1 of DB-OP-00000 states "Operations Personnel . . . shall be responsible for monitoring the equipment, instrumentation and controls within their area and taking timely and proper action to ensure safe, conservative operation of the unit." Contrary to those requirements, the channel 4 differential pressure switch was isolated and could not perform its function for a period of approximately 2 hours and 24 minutes, which was in excess of the time period that was specified in the TSs and in excess of the time period that the licensee had planned, without the knowledge of the operating control room crew and without the crew having the associated channel placed into a tripped condition. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 04-00181), it is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000346/2004002-04).

.3 Procedure Specified Heater not Available for EDG 2 Room

On January 25, 2004, the control room received unexpected annunciator alarm 1-1-K EDG 2 TRBL. The alarm was due to a low room temperature of 62°F in EDG 2 room. Supplementary actions in DB-OP-02037, Emergency Diesel Generator Alarm Panel 37 Annunciators," Revision 02 step 3.3 states in part "If the Shift Supervisor requests the use of a portable temporary heater, then....obtain a quartz-type heater". The shift engineer was tasked with determining the availability of a quartz type heater and contacting the appropriate personnel to have them installed. The licensee could not locate any quartz type heaters onsite.

The inspectors determined this to be a minor violation of TS 6.8.1.a which requires that written procedures be established and implemented for alarm conditions. Contrary to the procedural requirements of DB-OP-02037, the equipment required to respond to the alarm condition was not available. This was not an immediate safety issue and was determined to be of minor safety significance because the operators were able to install a different type of temporary heater which was able to raise the room temperature and clear the alarm. This issue was not subject to enforcement action in accordance with

Section IV of the NRC's Enforcement Policy. The licensee documented the issue in their corrective action program (CR 04-00652).

.4 Classification, Categorization, and Resolution of Restart Related Issues

The resident inspectors continued to monitor the licensee's activity related to properly classifying, categorizing and resolving their backlog of work orders, corrective actions, and modifications required to be completed prior to transitioning to Mode 4. To accomplish this, the inspectors:

- attended and assessed licensee management meetings;
- monitored the management of open Mode 2 and 1 restraints;
- evaluated the licensee classification of emergent deficient conditions; and
- evaluated closed Mode restraints.

As part of this inspection, the inspectors attended selected Mode Change Readiness Review meetings, and Senior Leadership Team meetings where classification of condition reports, prioritization of work activities, and setting of work completion dates took place.

The inspectors attended several Plant Support Center Meetings. The purpose of these meetings was to status significant restart equipment issues and focus licensee resources to efficiently and effectively work activities to provide more realistic work completion schedules.

The inspectors attended various work planning meetings. During the meetings there were discussions among the planners, workers, and management on the approaches needed to correct equipment issues.

No findings of significance were identified.

.5 Closure of Restart Checklist Items

The Davis-Besse Oversight Panel met to review the following two Restart Checklist Items and approved their closure:

a. Restart Checklist Item 2.a: Reactor Pressure Vessel Head Replacement

Inspection Procedure 71007, "Reactor Vessel Head Replacement Inspection," provided guidance on the recommended inspection activities to be conducted when a reactor vessel head is replaced. The scope of the inspection activities usually included: design and planning, reactor vessel head fabrication, reactor vessel head removal and replacement, and post-installation testing. The inspection activities also included evaluation of the temporary containment access opening and subsequent restoration following head replacement.

Inspection activities were performed to evaluate the licensee's performance in the following areas.

Design and Planning/Reactor Vessel Head Inspection
Inspection Report 05000-46/2002007 documented review of the non-destructive examinations performed on the replacement head welds that occurred at the Midland Michigan site and the American Society of Mechanical Engineers (ASME) Code data packages for the replacement head. Based on our inspection, we confirmed that adequate records were assembled to ensure that the replacement head was designed and fabricated in conformance with ASME Code requirements and that the original ASME Code Section III N-stamp remained valid.

Reactor Vessel Removal and Replacement
The physical removal of the old reactor vessel head from containment and the movement of the new reactor vessel head into containment were observed as routine resident plant status activities and were not specifically documented in an inspection report.

Inspection Reports 05000346/2002010 and 05000346/2003017 documented radiological inspections associated with head replacement activities. Specific inspection activities included:

- walkdowns of selected portions of the radiologically restricted area, including areas within the Auxiliary and Containment Buildings where significant radiological work involving the reactor head and containment breach was occurring;
- observed work occurring both inside and outside of the Containment Building including preparation for the reactor head moves and Containment Building breach;
- walkdowns of areas outside of the Containment Building where equipment for making the Containment breach was operating to verify that controls for containing radioactive materials generated in the breach process were adequate;
- reviewed the reactor head encapsulation process to verify that contamination control and radiological shielding were adequate to minimize dose to workers and to meet 10 CFR and 49 CFR requirements for the eventual transportation of the reactor head to a burial site; and
- observed aspects of the preparation of a shipment of the reactor head including the shipping documentation.

Containment Vessel Restoration
Inspection Report 05000346/2002007 documented that:

- the engineering evaluation associated with construction of the temporary containment access opening considered appropriate loads and demonstrated that stress in the containment shell materials would not exceed design limits;
- the temporary containment vessel opening was restored such that the original ASME Code construction requirements were maintained;
- the work activities to construct and restore the temporary containment opening and closure occurred in a controlled manner and in accordance with procedure requirements; and
- that the licensee managers demonstrated an active oversight role for the control of the contractors on the containment building temporary construction opening.

Inspection Report 05000346/2003005 documented that:

- based on the results of the containment integrated leak rate check, containment integrity had been restored where the containment had been opened for replacement of the reactor head.

Based on the results of these two inspection activities, the licensee's efforts to construct a temporary containment access, restoration of the temporary access following reactor head movement into containment, and subsequent leak testing were adequate.

Post Installation Testing
Inspection Report 05000346/2003023 documented inspection during reactor coolant system leak testing activities. The inspection included walkdowns of the reactor coolant system while at normal operating pressure as well as detailed evaluation of your inspections of the reactor vessel bottom head and closure head penetrations, and control rod drive mechanism flange connections following the 7 day pressure holding period. As a result of these pressure test activities, we have reasonable assurance that there are no pressure boundary leaks in the reactor coolant system.

Inspection Report 05000346/2004002 documented inspection of DB-SC-03270, "Control Rod Assembly Insertion Time Test." This activity was observed to evaluate proper control rod movement and reactor vessel head alignment. This test was successfully completed on February 10, 2004.

Conclusion
Based on the completion of the inspection activities described in this section, the inspectors concluded that sufficient basis existed for the closure of this checklist item. This was checklist item approved for closure by the Oversight Panel on February 10, 2004.

b. Restart Checklist Item 2.e (High Pressure Injection Pump Internal Clearance / Debris Resolution

This issue is discussed in this report under closure of LER 05000346/2003-002-01. The NRC staff evaluated the HPI pump modifications performed to address concerns identified by the licensee associated with the potential for debris to damage the pump during recirculation phase operation. The NRC review included evaluating the validity of the licensee's mock-up tests approach, determining whether the testing demonstrated acceptable pump performance under design-basis conditions. The NRC staff concluded in the TIA 2003-04 response dated February 11, 2004, that the licensee's overall approach to the modification of its HPI pumps and its testing, is acceptable and provided reasonable assurance that the HPI pumps will perform their required functions when called upon. See attached Task Interface Agreement 2003-04, "Evaluation of Davis-Besse Modifications to the High Pressure Injection Pump and Associated Mock-up Testing" for details of the staff's evaluation. In addition, the NRC staff evaluated a concern with the adequacy of the minimum flow capability provided for the pumps to prevent pump failure if the pumps were operated when no injection was occurring (NRC Inspection Report 05000346/2003010). NRC inspectors agreed with the licensee's determination that the pumps would be able to perform their safety function at the minimum flow of 53 gallons per minute based on the results of a minimum flow test performed with one of the pumps.

On February 19, 2004, the Davis-Besse Oversight Panel met to discuss this issue and concluded that Restart Checklist Item 2.e is closed.

.6 Performance of Technical Instruction 2515/154

Spent Fuel Material Control and Accounting at Nuclear Power Plants (TI 2515/154)

a. Inspection Scope

The inspectors, using the guidance contained in TI 2515/153, interviewed licensee personnel and reviewed spent fuel pool records to determine whether or not the licensee had ever removed irradiated fuel rods (pins) from a fuel assembly or reconstituted fuel assemblies. Based on the results of the interviews and reviews, the inspectors conducted additional interviews and reviews to gather general information concerning the licensee's Material Control and Accounting program.

b. Findings

The licensee first began removing irradiated fuel rods from assemblies and reconstituting assemblies in 1991. These activities were controlled according to vendor procedures prior to the implementation of the licensee's procedure, DB-NE-00100, "Fuel Handling Administration" on September 30, 1992. The licensees program tracks individual fuel rods from the point of removal from a fuel assembly to where they are stored in the spent fuel pool. All of these removed fuel rods are contained in a failed fuel basket assembly which is stored in the spent fuel racks. The failed fuel basket resembles a fuel assembly; however, it does not contain a top nozzle assembly and therefore its weight is much lighter than a normal fuel assembly. Spent fuel rods and the failed fuel assembly basket are physically separated from non-fuel components as to provide reasonable assurance that fuel and non-fuel items are not mistaken for each other.

The licensees Material Control and Accounting procedures are approved by the plant manager and controlled in accordance with their quality assurance program. The roles and responsibilities for all Material Control and Accounting activities are defined in procedure DB-NE-00100, "Fuel Handling Administration". The licensees written procedures for the movement of individual spent fuel rods within the spent fuel pool incorporates by reference the fuel vendors procedures. The organization responsible for documenting and maintaining records of discrete activities within the spent fuel pool is the Nuclear Fuels Department which has oversight of all spent fuel pool operations. The Nuclear Fuels Department maintains records documenting all spent fuel pool operations conducted by contractors and/or fuel vendors and performs an annual physical inventory of the spent fuel pool that includes resolution of all discrepancies.

4OA6 Meetings

.1 Resident Inspector Exit Meetings

The inspectors presented the inspection results to Mr. L. Myers, and other members of licensee management on February 25, 2004. The licensee acknowledged the findings presented. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exit meetings conducted:

- The closure of URI 50-346/02-014-06, related to relief valves, was discussed with Mr. B. Allen on January 23, 2004

- The inspection to review corrective actions for Licensee Event Report 50-346/03-001, related to potential inability of air-operated valves to function properly, was discussed with Mr. R. Schrauder on February 26, 2004, by telephone.

- The emergency preparedness program and performance indicators inspection results were discussed with Mr. L. Myers on February 13, 2004. A second exit meeting was conducted on the Emergency Action Levels with Mr. J. Vetter on February 27, 2004, by telephone.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

Cornerstone: Mitigation Systems

- 10 CFR 50, Appendix B, Criterion III, “Design Control,” requires, in part, that “measures shall be established for the identification and control of design interfaces and for coordination among participating organizations.” Contrary to this requirement, on May 21, 2003, the licensee identified a condition in which calculation and modeling errors occurred in the 1980s because of inadequate control of and coordination among various design organizations. Those errors resulted in a masonry wall within the auxiliary building whose design was insufficient to withstand concurrent HELB and seismic loading and which was not corrected until August 2003. The failure of this wall would potentially adversely affect components of TS required systems.

- Technical Specification 3.7.3.1 required the CCW system to be operable. Contrary to the above, the licensee operated since at least 1991 with this system not in an operable condition due to errors associated with installation of air operated valves (Section 4.0.A.3). At the time of discovery there were no applicable TS operability requirements for the affected systems with the reactor defueled. The licensee entered these issues into its corrective action program as PCAQR 97-1082, CR 02-07781, 03-01253, 03-05628, 99-2111, 03-00830, 03-04158, 02-07750, 03-01040, and CR 03-04878. The licensee performed additional calculations and relied on redundant safety equipment to demonstrate that this violation is not of more than very low safety significance.

- Technical Specification 3.7.4.1 required the SW system to be operable. Contrary to the above, the licensee operated since original plant construction with this system not in an operable condition due to errors associated with installation of air operated valves (Section 4.0.A.3). The licensee entered these issues into its corrective action program as PCAQR 97-1082, CR 02-07781, 03-01253, 03-05628, 99-2111, 03-00830, 03-04158, 02-07750, 03-01040, and CR 03-04878. The licensee performed calculations and relied on redundant safety equipment to demonstrate that this violation is not of more than very low safety significance.

- Technical Specification 3.6.3.1 required the containment isolation valves to be operable. Contrary to the above, the licensee operated since original plant construction with nonoperable containment isolation valves condition due to errors associated with installation of air operated valves (Section 4.0.A.3). At the time of discovery there were no applicable TS operability requirements for the affected systems with the reactor defueled. The licensee entered these issues into its corrective action program as PCAQR 97-1082, CR 02-07781, 03-01253, 03-05628, 99-2111, 03-00830, 03-04158, 02-07750, 03-01040, and CR 03-04878. The licensee relied on redundant safety equipment to demonstrate that this violation is not of more than very low safety significance.

Cornerstone: Barriers

- 10 CFR 50, Appendix B, Criterion III, “Design Control,” requires, in part, that “design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable test program.” Contrary to this requirement, LER 2003-05-01 identified a condition in which non-safety related instrument air was supplied at an insufficient pressure to the Containment Gas Analyzers. This inadequate design would have prevented the operation of the moisture trap drain check valves, during system operation post-accident, resulting in the eventual flooding of the hydrogen analyzer.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
M. Bezilla, Site Vice President
K. Byrd, Engineering
G. Dunn, Manager, Regulatory Affairs
J. Grabnar, Manager, Design Engineering
B. Henessy, Performance Engineering
L. Myers, Chief Operating Officer, FENOC
K. Ostrowski, Manager, Plant Operations
J. Powers, Director, Nuclear Engineering
R. Schrauder, Director, Support Services
M. Stevens, Director, Maintenance
S. Cope, Senior Emergency Planning Specialist
P. Smith, Emergency Planning Specialist
J. Vetter, Emergency Planning Supervisor

Ohio Emergency Management Agency
E. Edwards, Emergency Planning Specialist

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

50-346/2004002-01	FIN	Licensee not adequately prepared for the onset of frazil ice conditions (Section 1R01.1)
50-346/2004002-02	NCV	Change to Emergency Plan without prior NRC approval (Section 1EP4)
50-346/2004002-03	NCV	Failure to determine the cause and implement actions to prevent recurrence for the inadequate design changes made to the service water system valves at the outlet of the component cooling water heat exchangers (Section 4AO2)
50-346/2004002-04	NCV	Control room staff did not adequately monitor and control system status which resulted in a noncompliance with a TS Action Statement (Section 4OA5.2)

Closed

50-346/2003-002; Revisions 00 and 01	LER	Potential Degradation of High Pressure Injection Pumps Due to Debris in Emergency Sump Fluid Post Accident
50-346/2003-001; Revisions 00, 01, 02	LER	Potential Inability of Air-Operated Valves to Function During Design Basis Conditions
50-346/2003-005; Revisions 00 and 01	LER	Containment Gas Analyzer Heat Exchanger Valves Found Closed Rendering the Containment Gas Analyzer Inoperable.
50-346/2003-006	LER	Potential Errors in Analysis of Block Walls Regarding HELB Differential Pressure and Seismic Events
50-346/2003-013	LER	Unplanned Reactor Trip Condition with the Reactor Shutdown
50-346/02-014-06	URI	Question Regarding Licensee Compliance with Code Relief Valve Requirements.
50-346/03-021-01	AV	Potential Inability for HPI Pumps to Perform Safety Related Function

LIST OF DOCUMENTS REVIEWED

1R01 Adverse Weather Protection

DB-OP-06931; Seasonal Plant Preparation Checklist; Revision 07

CR 04-00179; Lack of Preparation for Frazil Ice Conditions

CR 04-00242; Intake Crib Mod to Prevent Ice Blockage May Ineffective

CR 04-00652; Procedure Specified Heater is not on Site

1R05 Fire Protection

Fire Hazards Analysis Report

Drawing A-224F; Fire Protection General Floor Plan Elevation 603' 0"

DB-FP-00009; Fire Protection Impairment and Fire Watch; Revision 05

1R13 Maintenance Risk and Emergent Work

Problem Solving Plan for RCP 2-2 High Seal Return Flow; January 4, 2004

CR 04-00057; Seal Return Flow Transmitter

WO 200077085; Troubleshoot/repair/replace FTMU60B

DB-OP-02515; Reactor Coolant Pump and Motor Abnormal Operation; Revision 05

DB-OP-02006; Reactor Coolant Pump Alarm Panel 6 Annunciators; Revision 07

CR 01-2019; Initial Results of Investigation into NRC Information Notice 2000-20

CR 04-00402; Door 515 May Not Have Sufficient Capacity for a HELB

CR 04-00442; MS Line Break in the Turbine Building Adversely Affects Doors in the Aux. Building

CR 04-00478; MS Line Break Potential Significant Effects

CR 03-11108; Bonnet Gasket Leakage on FW1009

CR 03-11199; FW1009 Valve Gasket Joint Leaking

CR 04-00463; FW1009, MDFP Discharge Check Valve Leaks

WO 200056845; Replace Bonnet Gasket on FW 1009

WO 200079617; DB-FW1009: Replace Bonnet Gasket

WO 200011379; DB-FW1009 MDFP to Main Feedwater Discharge Check

CR 04-00670; SV101C Leaks By When Energized

WO 200080939; DB-SV101C: Replace

CR 04-00737; AFPT 1 Casing Leak

DB-OP-06201; Main Steam System Operating Procedure; Revision 3

CR 04-00871; X01 A Phase Bushing Oil Leak

Problem Solving Plan for Startup Transformer X01 HV Bushing Leak

DB-SC-03020; 13.8 KV System Bus A & B Transfer Test; Revision 4

DB-SC-03020; 13.8 KV System Bus A & B Transfer Test; Revision 5

10 CFR 50.59 Evaluation for Changing TS Bases for Plant TS 3/4.8, Electric Power Systems

Switching Order to Service and Repair the Ohio Edison Beaver Line

Problem Solving Plan for Component Cooling Water Ventilation Train 2 Anomalies

DB-SC-04002; Component Cooling Water Pump Room Ventilation System - Train 2; Revision 01/Total Rewrite

CR 04-01231; CCW Pump Room Ventilation - Train 2 Control Logic Failure

WO 20007804; AFPT 1 Governor Fails to Control

CR 04-00105; AFW Turbine Governor

1R14 Personnel Performance During Nonroutine Plant Evolutions

DB-OP-06903; Plant Shutdown and Cooldown; Revision 13

DB-OP-06226; Startup Feed Pump Operating Procedure; Revision 05

DB-OP-06225; MDFP Operating Procedure; Revision 07

Operations Evolution Order Transfer to the SUFW Pump and Back to MDFP

DB-OP-06900; Plant Heatup; Revision 25

DB-OP-06005; RC Pump Operation; Revision 12

Operations Evolution Order to Allow Closure of MS101 for Maintenance on SV101C

DB-OP-06201; Main Steam System Operating Procedure; Revision 03

DB-SP-03300; RCS Isolation Check Valve Leak Test; Revision 01

DB-SC-04115; Absolute Position Indication Functional Test; Revision 02

1R19 Post-Maintenance Testing

Drawing E-44B Sheet 6A; Feedwater System AFP Suction Valves; Revision 13

Drawing E-44B Sheet 18; Feedwater System AFP Suction Valve Transfer Relay; Revision 05

DB-SP-03152; AFW Train 1 Level Control, Interlock and Flow Transmitter Test, Revision 09

WO 200076786; SP3152-001 04.000 Train 1 TAC 5.9

System Description 015; Auxiliary Feedwater System; Revision 02

WO 20032093; AFP 1 Suction Valve Transfer

DB-SP-04152; AFPT 1 TSS and Overspeed Trip; Revision 08

DB-SP-04153; AFPT 2 TSS and Overspeed Trip; Revision 07

DB-MM-09150; AFPT Maintenance; Revision 06

DP-SP-03445; SFRCS Channel 2 Trip of MS100 and MS101; Revision 03

WO 200080939; DB-SV101C: Replace

DB-SP-03444; SFRCS Channel 1 Trip of MS100 and MS101; Revision 03

1R20 Refueling and Outage

DB-OP-06900; Plant Startup; Revision 15

1R22 Surveillance Testing

DB-SP-03152; AFW Train 1 Level Control, Interlock and Flow Transmitter Test; Revision 09

DB-SC-03270; Control Rod Assembly Insertion Time Test; Revision 03

1R23 Temporary Plant Modifications

Temporary Modification 04-0002; K3-1 Auxiliary Feedwater Pump Turbine

10 CFR 50.59 Screen for the Temporary Spray Shield for Auxiliary Feed Pump Turbine Casing Leak

Problem Solving Plan for AFW Turbine #1 Casing Leak

CR 02-06767; LIR-AFW-JCL Inputs not Bounding

CR 04-00194; AFW Turbine K3-1 Casing Leak

4OA2 Problem Identification and Resolution

OPS-SAYS-I213.05; Auxiliary Feedwater System Description

DB-SP-03157; AFP 1 Response Time Test; Revision 07

DB-MM-090098; AFPT Governor Maintenance; Revision 04

CR 03-01964; OE-15688 AFW Pump Turbine Governor Linkage Binding

CR 03-08210; Misadjustment of Aux Feed Pump #1 Governor

CR 03-08108; AFW Train 1 Response Time Test Failure

CR 03-07975; Auxiliary Feedwater Train 1 Inoperability Due to Response Time

CR 03-07976; Auxiliary Feed Pump #1 Time Response

CR 03-08370; AFP Turbine K3-1 RPM Above Low Speed Stop Setting During Response Test

CR 04-00830; AFP 1 Response Time Exceeds Acceptance Criteria During DB-SP-03157

CR 04-00161; CAC Outlet Valves; dated January 6, 2004

CR 03-10371; Various CAC Related Equipment; dated December 1, 2003

CR 03-06837; Various; dated August 22, 2003

CR 02-07640; No ASME Code Review Documented; dated October 8, 2002

CR 02-06860; Various Heat Exchangers; dated September 27, 2002

PCAQR 88-0737; ASME Code Relief Protection; dated September 20, 1988

SE-95-0056; Removal of Containment Air Cooler Relief Valves; dated July 3, 1995

OS-020 So 1; Operational Schematic Service Water System; Revision 64

OS-020 So 2; Operational Schematic Service Water System; Revision 33

OS-004 So 1; Operational Schematic Decay Heat Removal Low Pressure Injection System; Revision 36

OS-004 So 2; Operational Schematic Decay Heat Removal Low Pressure Injection System; Revision 04

OS-021 So 1; Operational Schematic Component Cooling Water System; Revision 31

OS-021 So 2; Operational Schematic Component Cooling Water System; Revision 21

OS-021 So 3; Operational Schematic Component Cooling Water System; Revision 9

OS-041 So 1; Operational Schematic Emergency Diesel Generator Systems; Revision 19

DB-OP-06316; Diesel Generator Operating Procedure; Revision 12

DB-OP-06012; Decay Heat and Low Pressure Injection System Operating Procedure; Revision 16

DB-OP-06016; Containment Air Cooling System Procedure; Revision 13

DB-OP-06262; Component Cooling Water System Procedure; Revision 7

DB-OP-02000; RPS, SFAS, SFRCS Trip, or SG Tube Rupture; Revision 12

ECR 02-0343-00; Containment Air Cooler Upgrades; dated June 7, 2003

USAR Change Notice 97-073; Code Discrepancies; dated July 31, 1992

Specification No. 7749-M-400; TS for Containment Air Cooler Units; dated February 22, 1977

Specification No. 1024/1069; Heat Exchangers for Auxiliary System Service; dated November 14, 1968

Specification No. M-200; Piping Classes; Revision 6

Drawing M-033; Decay Heat Removal System and Emergency Core Cooling Systems; Revision 21

Drawing M-033B; Decay Heat Removal Train 1; Revision 43

Drawing M-033C; Decay Heat Removal Train 2; Revision 19

Drawing M-0368; Component Cooling Water System; Revision 31

Drawing M-036; Component Cooling Water System; Revision 15

Drawing M-041; Service Water System; Revision 18

Drawing M-041C; Service Water System for Containment Air Coolers; Revision 24

4OA3 Event Followup

CR 02-03859; Degraded Material Condition of the Containment Emergency Sump Screen

CR 02-05461; Past Operability of Containment Emergency Sump

CR 03-03398; Containment Gas Analyzer CCW Deficiencies

CR 03-04882; Containment Gas Analyzer Moisture Trap Design Issue - Potential Containment Bypass

CR 03-05529; Regulator in Air Supply Line to Hydrogen Analyzers Not On Drawings

CR 02-07169; LIR CCW - Lack of CCW Flow Verification to Essential Components

CR 03-04871; Containment Gas Analyzer Moisture Trap Design Issue

CR 03-05204; Asset Database Errors

CR 03-05605; Adequacy of Testing for TS Components

CR 02-08008; LIR CCW - Hydrogen Analyzer Function in SD-23 Not Consistent With USAR/Procedure

CR 03-05943; Overly Conservative Licensee Event Report (LER) Reporting Criterion

LER 2003-006; Potential Errors in Analysis of Block Walls Regarding HELB Differential Pressure and Seismic Events

Operability Evaluation 03-0015; Analysis for CR 03-05399

CR 03-02910; Seismic Analysis of Masonry Walls

CR 03-03937; Masonry Wall Failure

Root Cause Analysis Report for CR 03-02910 and CR 03-03937; July 11, 2003

CR 03-05399; Tornado Differential Pressure Analysis and Seismic Analysis of Masonry Walls

M-236B; Piping Isometric, Component Cooling System, Auxiliary Building El 565’-0"; Revision 14

LER 50-346/03-001; Potential Inability of Air-Operated Valves to Function During Design Basis Conditions; Revision 0 and Revision 1.

CR 03-05628; CCW Heat Exchanger 1-2 Outlet Control Valve

CR 03-04878; SW 1356, SW 1357, SW 1358 Air Accumulators

CR 03-04158; Component Cooling Water Service Water Outlet Isolation Valves

CR 03-01253; CCW To Nonessential Loads Isolation Valve

CR 03-01040; RCP Seal Return Isolation Valve

CR 03-00830; DH Heat Exchanger CCW Discharge Isolation

CR 02-07781; Service Water Outlet Valves From CAC Coolers

CR 02-07750; SW 1356, SW 1357, SW 1358

CR 99-2111; CC1495 Not Fully Closed

PCAQR 97-1082; Valve CC1495 Failed to Stroke Full Closed.

MPR Specification 200-037; Specification for Ball Valve Internal Design Information; Revision 0

MPR Specification 092-013-A5; Specification for Internal Design Information for Pivoting Cylinder Air Actuators With Spring Return; Revision 1

TV-1424; Valve/Damper Actuator and/or Accessories Information Sheet Davis-Besse; dated December 26, 2001

TV-1429; Valve/Damper Actuator and/or Accessories Information Sheet Davis-Besse; dated March 19, 1999

TV-1434; Valve/Damper Actuator and/or Accessories Information Sheet Davis-Besse; dated July 11, 2002

Kalsi Engineering Report 1666C; Engineering Evaluation of 12-Inch DACE-12 Neves Ball Valve Design Modification; dated August 3, 1990

C-ME-011.01-139; Component Level Review Calculation for AOV SW1424/1429/1434; Revision 0

C-ME-016.04-031; Maximum Expected Differential Pressure For Valves CC-1467 and CC-1469; Revision 0

C-ME-016.04-035; Component Level Review Calc For AOV CC1467/1469; Revision 0

C-NSA-099.16-80; Risk Assessment of Air Dependency for Component Cooling Water Heat Exchanger Valves SW 1424, SW 1434, SW 1429 and CC 1495; November 4, 2003

Component Cooling Water Heat Exchanger Service Water Outlet Isolation Valves Operability Analysis for Loss of Instrument Air During a Design Basis Accident; dated July 23, 2003

DB-PF-04167; Test to Evaluate the Dynamic Data During Stroking of SW 1434; dated July 14, 2003

Drawing ND-281547-01; D2CE-12 Valve With BJVAR20 Pneumatic Actuator; Revision T4

CR 04-00181; Missed TS Action Statement

CR 03-11314; Corrective Actions Taken to Improve Operational Deficiencies Appear Ineffective

CR 03-11033; RRATI - Operations Failure to Meet Standards and Expectations

CR 03-11414; Missed TS Entry

4OA5 Other Activities

DB-OP-00000; Conduct of Operations; Revision 07

DB-OP-03204; Channel Functional Test and Calibration of SFRCS Actuation Channel 2, Steam Generator Differential Pressure Inputs PDS-2685A, PDS-2685B, PDS-2686C, and PDS-2686D; Revision 05

CR-00181; Missed TS Action Statement

Root Cause Analysis Report for CR 2004-00181 dated January 18, 2004

DP-OP-06900; Plant Heatup; Revision 25

DB-SP-03302; CF 28 and CF 29 Leak Test; Revision 02

DB-OP-6911; Pre-Startup Checklist; Revision 07

1EP2 Alert and Notification System (ANS) Testing

Procedure RA-EP-00400; Prompt Notification System Maintenance; Revision 2

Procedure RA-EP-00420; Response to Prompt Notification System Malfunction; Revision 1

Internal Memorandum; RA-EP-00400 Annual Prompt Notification System Inspection; dated November 13, 2002

Internal Memorandum; RA-EP-00400 Biennial Prompt Notification System Siren Acoustic Testing; dated December 2, 2002

Internal Memorandum; 2003 Prompt Notification System Annual Inspection; dated August 2, 2003

1EP3 Emergency Response Organization (ERO) Augmentation Testing

Procedure RA-EP-00100; Emergency Plan Training Program; Revision 6

Procedure RA-EP-00550; Computerized Automated Notification System; Revision 2

Procedure RA-EP-02110; Emergency Notification; Revision 5

Records of Semi-Annual, Off-Hours, Unannounced Augmentation Drills - March 2002 Through September 2003

Training Records of a Random Sample of 30 Station Personnel Assigned to Key or Support ERO Positions

CR 03-05185; Review of Beaver Valley Plant's Second Unannounced Emergency Facilities Activation Drill

CR 03-08098; Several Persons Did Not Correctly Make Notification Data Entries During September 2003 Drill

CR 03-08197; Determine What is Optimum Identification Code to Use for Required Notification Data Entries

1EP4 Emergency Action Level (EAL) and Emergency Plan Changes

Davis-Besse Nuclear Power Station Emergency Plan; Table 4-1, Summary of Emergency Action Levels; Revision 22

EPIP RA-EP-01500; Emergency Classification; Revisions 3 and 4

Former EPIP EI-1300.01; Emergency Plan Activation; Revision 10

Internal Memorandum; Low Forebay Water Level Emergency Action Levels; dated December 22, 1988

Response to Request for Assistance on Low Forebay Water Level Emergency Action Levels; dated January 31, 1989

Internal Memorandum; Unusual Event of February 8, 1989; dated February 28, 1989

Internal Memorandum; Review of the Response to the Unusual Event of October 8, 1990; dated October 15, 1990

10 CFR 50.54(q) Review; Change 2 to Revision 3 of Emergency Classification Procedure's Toxic or Flammable Gas Emergency Action Levels; dated August 26, 1991

CR 04-00715; Evaluate EAL Issue at Point Beach Plant for Potential Impact on Davis-Besse

CR 04-01475; Revise an Indicator of EAL 5.A.1

CR-04-01500; Change Required to Emergency Classification Procedure RA-EP-01500

Review of EAL 1.D.1; dated February 11, 2004

Required Reading Packages on Changes to Emergency Classification Procedure; dated February 27, 2004

NRC Inspection Report 50-346/85011(DRSS); dated May 1, 1985

NRC Inspection Report 50-346/86007(DRSS); dated May 8, 1986

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

Davis-Besse Nuclear Power Station August 14, 2003 Blackout Unusual Event; undated

Internal Memorandum; Three 2002 Integrated Drills' Report; dated November 11, 2002

Internal Memorandum; April 10, 2003 Integrated Drill Report; dated June 9, 2003

Internal Memorandum; May 13, 2003 Dry Run Drill Report; dated June 30, 2003

Internal Memorandum; June 10, 2003 Evaluated Exercise Report; dated August 14, 2003

Internal Memorandum; July 31, 2003 Integrated Drill Report; dated September 29, 2003

Internal Memorandum; October 16, 2003 Integrated Drill Report; dated December 22, 2003

Internal Memorandum; 2002 Medical Drill Evaluation; dated November 11, 2002

Internal Memorandum; 2003 Medical Drills Evaluation; dated December 22, 2003

Internal Memorandum; December 26, 2002 Post Accident Sampling System Drill Report; dated February 24, 2003

Internal Memorandum; December 10, 2003 Post Accident Sampling System Drill Report; dated December 29, 2003

Davis-Besse Nuclear Quality Assessment Quarterly Report DB-C-02-02; dated August 9, 2002

Davis-Besse Nuclear Quality Assessment Quarterly Report DB-C-02-03; dated November 15, 2002

Davis-Besse Nuclear Quality Assessment Quarterly Report DB-C-02-04; dated February 19, 2003

Davis-Besse Nuclear Quality Assessment Quarterly Report DB-C-03-02; dated September 1, 2003

Davis-Besse Nuclear Quality Assessment Quarterly Report DB-C-03-03; dated November 17, 2003

Draft Davis-Besse Nuclear Quality Assessment Quarterly Report DB-C-03-04; dated January 13, 2004

Procedure RA-EP-00200; Emergency Plan Drill and Exercise Program; Revision 4

Procedure RA-EP-02010; Emergency Management; Revision 4

Training Handout to Radiation Protection Personnel on Expected Responses to a Steam Generator Tube Leak

CR 03-02926; Three Objectives Not Successfully Demonstrated During April 2003 Drill

CR 03-03831; Revise Notification Guidance for a Radiological Release in Progress That is Attributable to an Emergency Event

CR 03-03832; One Objective Not Adequately Demonstrated During May 2003 Drill

CR 03-04300; Provide More Training on Steam Generator Tube Leak Release Pathways

CR 03-04603; Assess Adequacy of Respirator Qualification Records and Spectacle Kits for Operations Support Center Staff

CR 03-04622; Reassess Roles of Liaisons Sent to State and County Response Facilities

CR 03-04739; Four Forms Used by ERO Responders or Drill Controllers Not Proceduralized

CR 03-06673; Emergency Preparedness Staff Training Provisions

CR 03-06737; Weaknesses in an ERO Training Session and Associated Lesson Plan

CR 03-07662; Evaluate High Temperature Alarm Set Point for the Davis-Besse Administration Building's Emergency Diesel Generator Room

CR 03-06831; Opportunities for Improvement From August 14, 2003, Unusual Event Response

CR 03-06835; Improve Procedures on Optional ERO Activation Following an Unusual Event Declaration

CR 03-07070; More Opportunities for Improvement From August 14, 2003, Unusual Event Response

CR 03-07165; Reassess Locations of ERO Telephones in the Control Room and Shift Manager's Office

CR 03-09018; Revise Joint Public Information Center Procedure to Address How to Handle an Event Reclassification During a Media Briefing

4OA1 Performance Indicator (PI) Verification

PI Desktop Guide for ERO Drill Participation; dated June 2003

PI Desktop Guide for ANS Reliability; dated January 2003

PI Desktop Guide for Drill and Exercise Performance Indicator; dated February 2002

Monthly Reports and Supporting Records for the ERO, ANS, and Drill and Exercise Performance Indicators - April 2003 Through December 2003

CR 02-00371; One Siren Failed to Sound During February 2002 Test

CR 02-02284; One Siren Failed to Sound During May 2002 Test

CR 02-02997; One Siren Had Motor Failure During July 2002 Test

CR 03-01854; One Siren Failed to Sound During March 2003 Test

CR 03-02410; One Siren Failed to Sound During Extra March 2003 Test

CR 03-04931; Notification Form Error During June 2003 Control Room Simulator Session

CR 03-06210; Notification Form Error During July 2003 Control Room Simulator Session

CR 03-06265; Wrong Notification Form Used by Emergency Control Center Staff During July 2003 Drill

CR 03-06769; Declining Trend in Drill and Exercise Performance Indicator

LIST OF ACRONYMS USED

ADAMS	Agency-wide Document Access and Management System
AFP	Auxiliary Feedwater Pump
AFPT	Auxiliary Feedwater Pump Turbine
AFW	Auxiliary Feedwater
ANS	Alert and Notification System
AOV	Air Operated Valve
ASME	American Society of Mechanical Engineers
AV	Apparent Violation
BWST	Borated Water Storage Tank
CAC	Containment Air Cooler
CCW	Component Cooling Water
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CGAS	Containment Gas Analyzers Systems
CR	Condition Report
DRS	Division of Reactor Safety
DHR	Decay Heat Removal
EAL	Emergency Action Level
ECCS	Emergency Core Cooling System
ECR	Engineering Change Request
EDGJW	Emergency Diesel Generator Jacket Water
EP	Emergency Preparedness
EPIP	Emergency Plan Implementing Procedure
ERO	Emergency Response Organization
FENOC	FirstEnergy Nuclear Operating Company
HELB	High Energy Line Break
HPI	High Pressure Injection
HRA	Human Reliability Analysis
IMC	Inspection Manual Chapter
IR	Inspection Report
LER	Licensee Event Report
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOIA	Loss of Instrument Air
NCV	Non-Cited Violation
NPSH	Net Positive Suction Head
NRC	United States Nuclear Regulatory Commission
NUREG	Nuclear Regulatory Guide
OP	Over-pressure
PARS	Publicly Available Records
PI	Performance Indicator
PORV	Pressure Operated Relief Valve
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
SDP	Significance Determination Process
SFAS	Safety Features Actuation System

SFRCS	Steam Feedwater Rupture Control System
SRA	Senior Reactor Analyst
SSC	Structures, Systems, Components
SW	Service Water
TIA	Task Interface Agreement
TRBL	Trouble
TS	Technical Specifications
URI	Unresolved Item
USAR	Updated Safety Analysis Report
WO	Work Order