July 30, 2003

EA-03-131

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 50-346/2003-015 - PRELIMINARY YELLOW FINDING

Dear Mr. Myers:

On June 30, 2003, 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 July 9, 2003, with you and other members of your staff. The inspection was an examination of activities conducted under your license as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your license. Within these areas, the inspection consisted of a selective review of procedures and representative records, observations of activities, and interviews with personnel. Since April 2002, 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. Even though the Reactor Oversight Process has been suspended at the Davis-Besse Nuclear Power Station, it was used as guidance for conducting inspection activities and to assessing findings.

This report discusses a finding that appears to have substantial safety significance and is being considered for escalated enforcement action in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600. The current Enforcement Policy is included on the NRC's website at http://www.nrc.gov/reading-rm/adams.html. As described in Section 4OA3.2 of this report, the finding involved the failure to promptly identify and correct significant conditions adverse to quality regarding unqualified coatings and uncontrolled fibrous material and other debris inside containment. This finding was assessed based on the best available information using the Significance Determination Process and was preliminarily determined to be a Yellow finding.

The preliminary significance of the finding is based on the increased likelihood of the emergency core cooling systems to fail following a loss of coolant accident. After injecting additional cooling water into the reactor following an accident, those systems begin recirculating cooling water to the reactor from the containment sump. The unqualified coatings, fibrous material and other debris could clog the screen on the sump blocking the water supply to the emergency core cooling system pumps. This increased likelihood of emergency core cooling system failure increases the probability of damage to the reactor following an accident. The increased probability was evaluated initiating Revision 3i of the Davis-Besse Standardized Plant Analysis Risk Model. The results of the evaluation indicated an increase in reactor core damage frequency of about 4 times in 100,000. Under the NRC's Significance Determination Process, this represents a Yellow finding. This increased risk existed from the time the facility began operation in 1977 until early 2002. The enclosure to this letter details the basis for the NRC's preliminary significance determination.

This finding does not present an immediate safety concern based on your immediate compensatory and corrective actions. These actions included a complete re-design of your emergency core cooling system sump strainer, and the reduction of potential debris sources in containment by recoating selected surfaces with approved coatings and the removal of other debris.

Before the NRC finalizes this significance determination, we are providing you an opportunity (1) to present to the NRC your perspectives on the facts and assumptions used by the NRC to arrive at the finding and its significance at a Regulatory Conference; or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within 30 days of the receipt of this letter and we encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more effective. If a Regulatory Conference is held, it will be open for public observation. If you decide to submit only a written response, such submittal should be sent to the NRC within 30 days of the receipt of this letter.

Please contact Christine Lipa at 630-829-9619 within 10 business days of the date of this receipt of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision and you will be advised by separate correspondence of the results of our deliberations on this matter.

Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for the inspection finding at this time. In addition, please be advised that the characterization of the apparent violation described in the enclosed inspection report may change as a result of further NRC review.

This report also documents one finding concerning a design deficiency in the emergency core cooling system high pressure injection pumps. That deficiency could result in damage or failure of the pumps following an accident. This is considered an apparent violation and the potential safety significance has not yet been determined. This finding does not present an immediate safety concern because the equipment is not required to be operable to support the current operational Mode of the plant. Additional review is necessary to determine the risk significance of this finding.

In addition, the enclosed report documents three self revealing violations of very low safety significance (Green). These findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these three findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any of the NCVs in this report, 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, United States Nuclear Regulatory Commission, Washington DC 20555-001; and the NRC Resident Inspector at Davis-Besse.

Since the terrorist attacks on September 11, 2001, NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance controls over access authorization. The NRC issued Temporary Instruction 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calendar year 2002, and the remaining inspection activities at Davis-Besse are scheduled for completion in September 2003. The NRC will continue to monitor overall safeguards and security controls at Davis-Besse.

In accordance with 10 CFR 2.790 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 50-346/03-015

See attached distribution

cc w/encl: The Honorable Dennis Kucinich
B. Saunders, President - FENOC
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Manager - Regulatory Affairs
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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-346
License No:	NPF-3
Report No:	50-346/2003-015
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Davis-Besse Nuclear Power Station
Location:	5501 North State Route 2 Oak Harbor, OH 43449-9760
Dates:	May 18 through June 30, 2003
Inspectors:	S. Thomas, Senior Resident Inspector J. Rutkowski, Resident Inspector R. Gibbs, Senior Reactor Analyst
Approved by:	C. A. Lipa, Chief Branch 4 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000346/2003-015; 5/18/2003 - 6/30/2003; FirstEnergy Nuclear Operating Company, Davis-Besse Nuclear Power Station; Event Followup, Maintenance Effectiveness, Personnel Performance During Nonroutine Plant Evolutions.

This report covers a 6-week period of resident inspection. The inspection was conducted by resident inspectors. One preliminary Yellow Apparent Violation, one Unresolved Item with safety significance to be determined, and three Green Non-Cited Violations were 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>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Mitigating Systems

- <u>Yellow</u>. An Apparent Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified for the failure to promptly identify and correct significant conditions adverse to quality regarding the implementation of corrective actions for design control issues related to deficient containment coatings, uncontrolled fibrous material and other debris. This impacted the ability of the emergency core cooling system sump to perform its function under certain accident scenarios due to clogging of the sump screen by unqualified coatings, fibrous materials, and various other debris.

  The issue is more than minor because the failure to implement appropriate corrective actions resulted in an actual loss of safety function of the ECCS system. The significance determination evaluation for this finding is documented in this report. (Section 4OA3.2)

- <u>TBD</u>. An apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified for the failure to adequately implement design control measures for verifying and checking the adequacy of the original design of the high pressure injection pumps for all postulated accidents.

  The finding is Unresolved pending completion of a significance determination. The finding is more than minor because it: (1) involves the design control attribute of the Mitigating Systems cornerstone; and (2) affects the cornerstone objective of ensuring the availability, and capability of systems that respond to initiating events to prevent undesirable consequences. Because the finding described above represents a potential loss of safety function of the HPI system, a Significance Determination Process (SDP) Phase 2 analysis was required. The inspectors utilized SDP worksheets for the Davis-Besse Nuclear Power Station to perform a Phase 2 evaluation of the finding. Based on this evaluation, the finding was determined to have potential safety significance greater than very low safety significance. (Section 4OA3.1)

- Green. A self-revealing Non-Cited Violation of Technical Specification 6.8.1.a was identified for failing to provide adequate procedural guidance for tightening fasteners internal to the high pressure injection pump. As a direct result, five socket head cap screws, located near the discharge of the pump, failed during pump testing.

  The finding is greater than minor because it: (1) involves the procedure quality attribute of the Mitigating System cornerstone; and (2) affects the cornerstone objective of ensuring the availability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding is of very low safety significance because no actual loss of a safety function occurred due to the failure of the cap screws. (Section 1R12)

Cornerstone: Initiating Events

- Green. A self-revealing Non-Cited Violation of Technical Specification 6.8.1.a was identified for failing to properly implement system procedures during the filling of the circulating water system. Since three drain valves were improperly left open during the fill, approximately three inches of water flooded the 565' elevation of the turbine building.

  The finding is greater than minor because it: (1) involves the configuration control attribute of the Initiating Event Cornerstone; and (2) affects the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The finding is of very low safety significance because the event was terminated prior to actual loss of a equipment important to plant safety. (Section 1R14)

Cornerstone: Barriers

- Green. A self-revealing Non-Cited Violation of Technical Specification 6.8.1.a was identified for failing to perform work in accordance with approved maintenance procedures during the installation of reactor coolant pump mechanical seal RTDs. As a direct result, the RTD tubing nuts were not installed to a sufficient tightness to provide a leak tight joint at normal operating pressure.

  The finding is greater than minor because if left uncorrected, it would become a more significant safety concern. Investigation by the licensee revealed that the RTD tubing nuts were not installed to a sufficient tightness to provide a leak tight joint at normal operating pressure. The finding is of very low safety significance because the current operational Mode does not challenge the integrity of the RTD mechanical joints. (Section 1R12)

B. Licensee-Identified Violations

A violation of very low safety significance, which was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and corrective actions are listed in Section 4OA7 of this report.

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.” The fuel was removed from the reactor on June 26, 2002, and the plant remained shut down. The plant entered operational Mode 6 on February 19, 2003 and fuel reload was completed on February 26, 2003. The plant entered operational Mode 5 on March 12, 2003. For the entire inspection period, the Davis-Besse Nuclear Power Station was under the IMC 0350 Process. As part of this Process, several additional team inspections continued. The subjects of these inspections included: Containment Health/Extent of Condition, System Health Assurance, Management and Human Performance, and Program Compliance. The status of these inspections will not be included as part of this inspection report, but upon completion, each will be documented in a separate inspection report which will be made publicly available on the NRC website.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection

.1 Annual Inspections (71111.01)

a. Inspection Scope

The inspectors verified that the licensee had established procedures and had implemented actions to mitigate the potential adverse effects from the annual mayfly swarms. The inspectors verified that there were regular operator tours to inspect equipment that could be impacted by mayfly swarms blocking cooling mechanisms or affecting electrical resistance. Additionally, the inspectors verified that operators conducting tours were familiar with established tour requirements, could identify potential problems from mayfly swarms, and that procedural requirements had been appropriately inputted to the handheld devices used by the operators for recording tour data. A majority of the inspector’s time was spent performing walkdown inspections with operations personnel while they conducted tours. Key aspects of the walkdown inspections included:

- checking ventilation filters free from excessive buildup of mayflies and other material that could impair ventilation flow;
- verifying that potentially effected switchgear and pump ventilation inlets were not clogged or did not have severely restricted passages;
- verifying lake facing doors and dampers were closed during the night hours, if permitted by plant conditions, to reduce mayfly influx to buildings; and

- verifying that lighting, not necessary for security or other plant conditions, was adjusted as practical to reduce attraction of mayflies.

During the walkdowns, the inspectors also observed the material condition of the equipment to verify that there were no significant conditions not already in the licensee's work control system.

b. Findings

No findings of significance were identified

1R05 Fire Protection (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns 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 areas were inspected:

- containment building (fire zone D) including the east D-ring; and
- component cooling water heat exchanger and pump room.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q)

a. Inspection Scope

The inspectors reviewed the licensee's overall maintenance effectiveness for risk-significant mitigating structures, systems, and components (SSCs). This evaluation consisted of the following specific activities:

- observing the conduct of planned and emergent maintenance activities where possible;
- reviewing selected CRs, open WOs, and control room log entries in order to identify system deficiencies;

- reviewing licensee system monitoring and trend reports; and
- a partial walkdown of the selected SSCs listed below.

The inspectors also reviewed whether the licensee properly implemented the Maintenance Rule, 10 CFR 50.65, for the SSCs. Specifically, the inspectors determined whether:

- the SSCs were scoped in accordance with 10 CFR 50.65;
- performance problems constituted maintenance rule functional failures;
- the system had been assigned the proper safety significance classification;

The above aspects were evaluated using the maintenance rule program and other documents listed in the Attachment.

The inspectors reviewed the following SSCs:

- high pressure injection pump 1 (rotating element disassembly);
- high pressure injection pump 1 (installation of modified rotating assembly for rotordynamic testing); and
- reactor coolant pump seal RTD installation rework.

b. Findings

.1 High Pressure Injection Pump Rotating Element Disassembly

Introduction: A Green self-revealing Non-Cited Violation of Technical Specification 6.8.1.a was identified for failing to provide adequate procedural guidance for tightening fasteners internal to the high pressure injection pump. As a direct result, five socket head cap screws, located near the discharge of the pump, failed during pump operation.

Description: On June 1, 2003, the licensee was removing the rotating assembly from high pressure injection pump 1 in preparations for shipping it to the vendor for modification. While making preparations for the removal of the high pressure injection pump 1 rotating assembly from its associated pump barrel casing, the licensee discovered that five of the six cap screws were sheared where the threads met the shank. Although the sixth cap screw was intact, it showed signs of impending failure.

This rotating assembly had recently been repaired at a vendor maintenance facility, with direct licensee oversight, in accordance with Davis-Besse Mechanical Maintenance Procedure DB-MM-09173, “High Pressure Injection Pump Maintenance,” Revision 02. As part of the rotating assembly reassembly process, an internal head plate is installed. Step 8.7.45 provided the instructions for installing the six internal head plate socket head cap screws which secured the head plate. The instructions provided were “install internal head plate pins with locking devices and tighten securely.” There was no reference to the proper torque value for these cap screws. The procedure was inadequate because it did not provide proper tightening instruction for installing the internal head plate cap screws. Further evaluation by the licensee revealed that the proper torque value for these cap screws was relatively small (70 in-lbs). This torque value can easily be exceeded with a small wrench.

Although the failure of these cap screws did not pose a significant challenge to the operation of the high pressure injection pump, they did present a loose parts issue. Once the failure of the cap screw occurred, there was no physical barrier preventing the cap screw from entering the discharge flow exiting the pump, being transported to the reactor coolant system, and eventually the reactor. In this case, all of the failed cap screws remained in place. As part of the corrective actions implemented to address this deficiency, the licensee modified DB-MM-09173, step 8.7.46(b) as follows; “torque internal head plate socket heat cap screws to 70 in-lbs.”

Analysis: In accordance with IMC 0609, Appendix A, Attachment 1, the inspectors performed a SDP Phase 1 screening and determined that the issue affected the Mitigating Systems Cornerstone. The finding was of more than minor safety significance because it: (1) involved the procedure quality attribute of the Mitigating System cornerstone; and (2) affected the cornerstone objective of ensuring the availability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding is of very low safety significance because no actual loss of a safety function occurred due to the failure of the cap screws.

Enforcement: The performance deficiency associated with this event is the failure to provide adequate procedural guidance in a safety-related maintenance procedure which provides guidance for tightening fasteners internal to the high pressure injection pump. Technical Specification 6.8.1.a requires establishing and implementing procedures required by Regulatory Guide 1.33. Regulatory Guide 1.33 requires procedures for maintenance which can affect the performance of safety-related equipment. The licensee developed Procedure DB-MM-09173, “High Pressure Injection Pump Maintenance,” Revision 02, which provides guidance for the maintenance of the high pressure injection pumps. Contrary to the requirements of Technical Specification 6.8.1.a, Procedure DB-MM-09173 did not provide adequate procedural guidance for tightening the internal head plate socket head cap screws. As a direct result, five socket head cap screws, located near the discharge of the pump, failed during pump operation. Because of the very low safety significance and because the issue has been entered into the licensee’s corrective action program (CR 03-04278) it is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-346/03-015-01).

.2 Reactor Coolant Pump Seal Resistance Temperature Detector (RTD) Installation Rework

Introduction: A self-revealing Non-Cited Violation of Technical Specification 6.8.1.a was identified for failing to perform work in accordance with approved maintenance procedures during the installation of reactor coolant pump mechanical seal RTDs. As a direct result, the RTD tubing nuts were not installed to a sufficient tightness to provide a leak tight joint at normal operating pressure.

Description: During the current refueling outage, the seal packages were replaced on all four reactor coolant pumps. As part of the seal change-out process, the RTDs that measured the temperature of each of the seal's three stages (3 per pump) were removed and subsequently reinstalled during seal assembly. These RTDs were secured in place by mechanical fittings. The leak tightness of these fittings was checked during the 50 psig and 250 psig reactor coolant system pressure tests. During evaluation of the fittings while the reactor coolant system was pressurized, the licensee identified that 4 of the 12 RTD fittings exhibited signs of leakage. As part of the licensee's corrective actions to address the leakage, new RTDs, O-rings, fittings, and tubing connectors were installed in four of the RTD locations. During the RTD installation process, when the workers discovered that each RTD was not secure after using the guidance described in the work instructions, they continued to tighten the tubing nut an additional ½ turn to secure the RTD. This was a deviation from the instructions in the work package. After the required reactor coolant pump mechanical seal RTD work was completed, the reactor coolant system was refilled, vented, and pressurized to approximately 40 psig. No leakage was noted from the fittings where the RTDs had been replaced, but leakage was noted from another RTD fitting. During the licensee's investigation into why the fitting was leaking, they discovered the maintenance deviation that had occurred during the replacement of the four RTDs. Additionally, the licensee discovered that the original guidance in the work instructions for tightening the tubing nut (hand tight plus 3/4 of a turn) was insufficient to provide a leak tight joint. The correct instructions should have been to tighten the tubing nut to hand tight plus 1 3/4 turns. As part of the corrective actions for this issue, the licensee planned to tighten the tubing nuts on the four replaced RTDs and the remaining leaking RTD to the correct value prior to operational Mode 4 and verify leak tightness at full operating pressure.

Analysis: In accordance with IMC 0612, Appendix B, the inspectors determined that the issue was of more than minor safety significance because if left uncorrected, it could become a more significant safety concern. Investigation by the licensee revealed that the RTD tubing nuts were not installed to a sufficient tightness to provide a leak tight joint at normal operating pressure. In accordance with IMC 0609, Appendix A, Attachment 1, the inspectors performed a SDP Phase 1 screening and determined that the issue affected the Barriers Cornerstone. The finding is of very low safety significance because the current operational Mode of the did not challenge the integrity of the RTD mechanical joints.

Enforcement: The performance deficiency associated with this event is the failure to perform work in accordance with approved maintenance procedures. Technical Specification 6.8.1.a requires implementation of procedures required by Regulatory Guide 1.33. Regulatory Guide 1.33 requires procedures for maintenance which can affect the performance of safety-related equipment. The licensee developed DB-MN-00001, "Conduct of Maintenance," Revision 10, a procedure affecting quality, to provide general guidance for the conduct of maintenance at the Davis-Besse facility. Step 6.5.2(c) states that "tasks shall be completed as described in the latest approved version of the work document." Contrary to this requirement, on four separate occasions, RTD tubing nuts were tightened in excess of the guidance provided in the work control document without first obtaining a formal change to the work document. Further evaluation by the licensee revealed that, although the additional tightening was sufficient to prevent axial movement of the RTD during installation, it was still insufficient to ensure a leak tight seal at normal operating pressure. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 03-04773) it is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-346/03-015-02).

.3 High Pressure Injection Pump Installation of Modified Rotating Assembly for Special Test

On June 5, 2003, to support the validation of the licensee's proposed modifications for the high pressure injection pumps, a modified rotating assembly was installed into high pressure injection pump 1 for testing. During the installation process, the torque applied to the casing bolts was approximately 4.3% in excess of the desired torque. This error occurred because a maintenance worker failed to check that a gauge which was part of the hydraulic torque wrench being used to tighten the casing nuts was in calibration as required by DB-MM-09173, "High Pressure Injection Pump Maintenance," Revision 4. Subsequent evaluation revealed that the gauge indicated approximately 200 psig low, which corresponded to an additional 77 ft-lbs of torque being applied to the pump casing nuts in excess of the 1785 ft-lbs required by the procedure. This issue was further discussed in Section 4OA7 of this report.

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 risk significant issues were evaluated by the inspectors:

- the loss of all source range nuclear instruments during the testing of nuclear instruments 3 and 4;
- the disassembly and removal from service of both high pressure injection pumps;
- reactor coolant system draining to 54 inches and the implementation of the developed contingency plan for the evolution; and
- reactor coolant pump mechanical seal RTD replacement work.

b. Findings

No findings of significance were identified. The risk categorization and the implementation of the developed contingency plan for the reactor coolant system draining activity was further discussed in 4OA5.1 of this report.

1R14 Personnel Performance During Nonroutine Plant Evolutions (71111.14)

.1 Circulating Water System Fill

a. Inspection Scope

The inspectors reviewed operations personnel conduct during the filling of the circulating water system to determine if the evolution was conducted in a safe and conservative manner. The inspectors reviewed TSs, operations procedures, and facility administrative procedures to determine the acceptance criteria for the inspection.

b. Findings

Introduction: A Green self-revealing Non-Cited Violation of Technical Specification 6.8.1.a was identified for failing to properly implement system procedures during the filling of the circulating water system. As a direct result of three drain valves being improperly left open during the system fill, approximately three inches of water deposited on the 565' elevation of the turbine building.

Description: On May 12, 2003, System Procedure DB-OP-0632, Attachment 1, "Circulating Water System Fill Valve Checklist," was completed as part of the preparations for filling the circulating water system. The general timeline of the event was as follows:

- 5/15/03 (21:00): conducted a brief for filling the circulating water system
- 5/16/03 (00:05): commenced filling the circulating water system
- 5/16/03 (00:40): increased fill rate
- 5/16/03 (01:49:06): west condenser pit sump level high level alarm in
- 5/16/03 (01:49:12): west condenser pit sump level high level alarm clear
- 5/16/03 (02:01:15): west condenser pit sump level high level alarm in
- 5/16/03 (02:01:30): west condenser pit sump level high level alarm clear
- 5/16/03 (02:04:56): west condenser pit sump level high level alarm in
- 5/16/03 (02:13:34): west condenser pit sump level high level alarm clear
- 5/16/03 (02:23:34): Bus 2 DC system ground alarm in
- 5/16/03 (02:36): Electrician reports water on 565 foot elevation of turbine building. Operators dispatched to investigate find CT50 [HP Condenser 1 Water Box #1 Inlet Drain Valve] and CT51 [LP Condenser 2 Water Box #1 Outlet Drain Valve] open. The

operators placed the valves in their required position (closed).

- 5/16/03 (02:47): stopped filling the circulating water system;
- 5/16/03 (06:07): A valve lineup of the circulating water valves in the condenser pit revealed an additional valve, CT17 [HP Condenser 1 Water Box #1 Drain Valve] was also open.

The three 8-inch rising stem gate valves, CT17, CT50, and CT51, were required to be closed and were signed for as being in that position on DB-OP-0632, Attachment 1, “Circulating Water System Fill Valve Checklist,” prior to commencing the circulating water system fill.

The Equipment Operator that performed the circulating water system valve lineup was interviewed as part of an apparent cause evaluation for this event. Information gained from this interview included:

- the operator had successfully closed CT16, CT14, and CT13 (the same type of rising stem gate valves as CT17, CT50, and CT51);

- after unsuccessfully attempting to close CT17, CT50 and CT51, the operator did not ask for assistance in closing the valves; and

- even though he was unsure about the position of the three drain valves, he initialed the Circulating Water System Fill Valve Checklist for the valves being closed without first elevating his concern to his supervisor.

Operations Administrative Instruction DB-OP-01002, “Component Operation and Verification,” Revision 00, a safety related procedure, provided direction and guidance for the manipulation of components for the purposes of system operation, lineup, verification, and testing. Some specific guidance given by this procedure included:

- “When performing manual valve manipulations, they shall be performed with sufficient force to ensure the valve is in the proper position”;

- “To check a manual valve or stop check valve closed, attempt to move the valve handwheel in the closed direction”; and

- “Verifying the valve in the proper position would consist of first checking the current position as described above and then repositioning the valve to the desired position if needed. Other methods to confirm desired position should be used when available such as remote valve position indicator, stem position, local valve position indicator, and process variables.”

The Equipment Operator did not effectively implement the guidance for conducting valve lineups contained in DB-OP-01002 or demonstrate a proper questioning attitude as outlined in the Davis-Besse Business Practice DBBP-OPS-0001, “Operations Expectations and Standards,” Revision 04.

Administrative Procedure DB-OP-0000, “Conduct of Operations,” Revision 06, a safety related procedure, states that Operations personnel shall “be alert for any unusual trends in plant parameters, early signs of abnormal situations, and ensure the Control Room and supervision are notified.” Even though the crew had been briefed and the Control Room staff knew that potential for flooding existed during the fill of the circulating water system, they took no specific actions to investigate the cause of several west condenser pit high level alarms, which occurred in a short period of time. It wasn’t until a field electrician notified the Control Room of the water on the floor in the condenser pit area, that action was taken to investigate the problem. The control room staff did not demonstrate a proper questioning attitude as outlined in the Davis-Besse Business Practice DBBP-OPS-0001, “Operations Expectations and Standards,” Revision 04.

Analysis: In accordance with IMC 0609, Appendix A, Attachment 1, the inspectors performed a SDP Phase 1 screening and determined that the issue affected the Initiating Events Cornerstone. The finding was more than minor because it: (1) involved the configuration control attribute of the Initiating Event Cornerstone; and (2) affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety fuctions during shutdown as well as power operations. The finding was of very low safety significance because the event was terminated prior to actual loss of a equipment important to plant safety.

Enforcement: The performance deficiency associated with this event is the failure to correctly implement procedures required for plant operation. Technical Specification 6.8.1.a requires implementation of procedures required by Regulatory Guide 1.33. Regulatory Guide 1.33 requires procedures for General Plant Operation. The licensee developed DB-OP-06232, “Circulating Water System and Cooling Tower Operation,” Revision 05, a procedure affecting quality, to, in part, provide instructions on filling the circulating water system. Contrary to the requirements of Technical Specification 6.8.1.a, System Procedure DB-OP-0632, Attachment 1, “Circulating Water System Fill Valve Checklist,” was completed with three drain valves left in the incorrect (open) position. As a result, approximately three inches of water flooded the 565' elevation of the turbine building. Because of the very low safety significance and because the issue has been entered into the licensee’s corrective action program (CR 03-03815) it is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-346/03-015-03).

.2 High Pressure Injection Pump 1 Enhanced Baseline Testing in Piggyback Mode

a. Inspection Scope

The inspectors reviewed operations personnel conduct during the development and implementation of Special Test Procedure DB-SP-10030, “HPI Pump 1 Mode 5 Enhanced Baseline Testing in Piggyback Mode.” The test was developed to collect data relevant to the validation of rotordynamics analysis modeling and associated post accident condition of the rotating assembly of the high pressure injection pumps. This test was conducted utilizing a modified rotating element which had increased wearing ring clearances to simulate degrade pump conditions. The inspectors verified that the required procedure reviews and safety screening were performed and were adequate, that the required plant conditions were maintained to support the test, and that operations personnel conducted the evolution in a safe and conservative manner.

b. Findings

No findings of significance were identified.

.3 Reactor Coolant Drain from level of 80 inches to 54 inches above hot leg

a. Inspection Scope

The inspectors reviewed operations personnel conduct during the drain and venting of the reactor coolant system (RCS) work in preparation for work on reactor coolant pump seal package resistance temperature detectors (RTDs). The license had identified the draining evolution as placing the plant in an orange risk condition and had developed a contingency plan for the period of time spent in an orange risk plant configuration. The RCS had previously been drained to approximately 80 inches above the centerline of the RCS hot leg loop. Work on the RTDs required draining to 54 inches or less and venting the reactor coolant pump seal package to break the vacuum created in reactor coolant pump to minimize potential adverse siphon effects that could be caused by the vacuum.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors selected condition reports (CRs) which discussed potential operability issues for risk significant components or systems. These CRs were evaluated to determine whether the operability of the components or systems was justified. The inspectors compared the operability and design criteria in the appropriate sections of the Technical Specifications and USAR to the licensee's evaluations presented on the issues listed below to verify that the components or systems were operable. Where compensatory measures were necessary to maintain operability, the inspectors verified that the measures were in place, would work as intended, and were properly controlled.

The issues evaluated were:

- Operability Evaluation 2002-0023, Revision 3 (addressed safety related components cooled by non-safety ventilation in the high voltage switchgear rooms and auxiliary shutdown panel room);
- Operablity Evaluation 2003-0009, Revision 1 (addressed emergency diesel generator low frequency and low voltage during safety features actuation loading conditions); and
- Operability Evaluation 2002-0039, Revision 2 (addressed emergency diesel generator maximum room temperature).

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors witnessed the following surveillance test and 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 activity was selected based on its importance in verifying mitigating system capability. 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 test was observed and evaluated:

- CC-1467, Component Cooling Water From DH Removal Cooler 1-1 Outlet Valve, Timing Test.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

- The inspectors reviewed Temporary Modification 03-016, “Install a Temporary Jumper to Pressurize EDG 2 Receiver 2-1 and Receiver 2-2 directly from EDG Air Compressor 2 During Cross-tie Piping Work,” to verify that the modification did not affect the safety functions of risk significant safety systems. This temporary modification was put in place to maintain a reliable source of starting air for emergency diesel generator 2 while modifications were performed on the emergency diesel 1 air start compressors and piping.

- The inspectors reviewed Temporary Modification 03-017, “Second Stage Seal Temperature on RCP1-2."

  The inspectors reviewed these temporary modification and associated 10 CFR 50.59 screenings against system requirements, including the USAR and TS 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.

4. OTHER ACTIVITIES

4OA3 Event Followup (71153)

.1 (Discussed) Licensee Event Report (LER) 50-346/03-002: Potential Degradation of High Pressure Injection (HPI) Pumps Due to Debris in Emergency Sump Fluid Post Accident

a. Inspection Scope

The inspectors reviewed LER 2003-002, which documented an issue in which debris from the containment sump would impact the high pressure injection (HPI) pumps, following a design basis accident, whereby the pump internals would be damaged to the extent that would impact the pumps' ability to complete their intended safety function.

b. Findings

Introduction: An apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified for the failure to adequately implement design control measures for verifying and checking the adequacy of the original design of the HPI pumps for all postulated accidents.

Description: 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. 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.

On April 7, 2003, the licensee reported this deficiency to NRC. Subsequently, on May 5, 2003, the licensee submitted a 10 CFR 50.73 report, which documented this issue. The report was submitted pursuant to the following reporting requirements:

- as a condition that could have prevented the fulfillment of the safety function of a system needed to maintain the reactor in a safe condition and remove residual heat;
- as a single condition that caused two independent trains to become inoperable in a single system designed to remove residual heat; and
- as a condition that resulted in the nuclear power plant being in an unanalyzed condition that significantly degraded plant safety.

The licensee planned to replace or modify both of the HPI pumps, prior to restart, to eliminate the potential for blockage of cooling water to the HPI hydrostatic bearings during the piggyback mode of operations utilizing water from the containment ECCS sump.

Analysis: In accordance with IMC 0609, Appendix A, Attachment 1, the inspectors performed a SDP Phase 1 screening and determined that the issue affected the Mitigating Systems Cornerstone. The finding is more than minor because it: (1) involves the design control attribute of the Mitigating Systems cornerstone; and (2) affects the cornerstone objective of ensuring the availability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors evaluated the significance of this issue using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." Because the finding described above represented an actual loss of safety function of the HPI system, a Significance Determination Process Phase 2 analysis was required. The inspectors utilized SDP worksheets for the Davis-Besse Nuclear Power Station to perform a Phase 2 evaluation of the finding. The finding was determined to have potential safety significance greater than very low safety significance. Although the facility operated with this deficiency prior to entering the current extended shutdown, the finding was not an immediate safety concern because the HPI pumps are not required to support the current operational Mode of the reactor plant. The finding is unresolved pending completion of a final significance determination.

Enforcement: The performance deficiency associated with this event is the failure to correctly implement design control measures for verifying the adequacy of the original design for the HPI pumps to mitigate all postulated accidents. 10 CFR 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established to assure that the design basis for safety-related functions of structures, systems, and components are correctly translated into specifications, drawings, procedures, and instructions. Further, Criterion III requires that the design control measures shall provide for verifying and checking the adequacy of design. Contrary to the above, the licensee failed to adequately implement design control measures for verifying and checking the adequacy of the original design of the HPI pumps. Pending determination of the finding's final safety significance, this finding is identified as URI 50-346/03-15-04, Potential Inability for HPI Pumps to Perform Safety Related Function.

.2 (Discussed) Licensee Event Report (LER) 50-346/02-005-00, 50-346/02-005-01, 50-346/02-005-02: Potential Clogging of the Emergency Sump Due to Debris in Containment

a. Inspection Scope

The inspectors reviewed LER 2005-002, and subsequent revisions, which documented an issue involving the potential clogging of the emergency sump by debris generated during specific reactor accidents.

b. Findings

Introduction: A apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action," was identified was identified for the failure to effectively implement corrective actions for design control issues related to deficient containment coatings, uncontrolled fibrous material, and other debris. This deficiency resulted in the inability of the emergency core cooling system sump to perform its safety function under certain accident scenarios due to clogging of the sump screen.

Description: On September 4, 2002, with the reactor defueled, the licensee determined that the existing amount of unqualified containment coatings and other debris (e.g., fibrous insulation) inside containment could have potentially blocked the emergency sump intake screen, rendering the sump inoperable following a loss of coolant accident. The unqualified coatings and fibrous insulation had existed since original construction. The licensee declared the emergency sump inoperable and entered the deficiency into their corrective action program. With the emergency sump inoperable, both independent emergency core cooling systems (ECCS) and both containment spray (CS) systems are inoperable, due to both requiring suction from the emergency sump during the recirculation phase of operation. This could prevent both trains of ECCS from removing residual heat from the reactor and could prevent CS from removing heat and fission product iodine from the containment atmosphere.

The licensee reported this information in LER 2002-05 on November 4, 2002. On December 11, 2002, the licensee submitted Supplement 1 in which the licensee stated that a debris generation and transport analysis would be performed. In Supplement 2 dated May 21, 2003, the licensee indicated that the debris generation and transport analysis would be provided. Subsequently, on May 28, 2003, the licensee informed the NRC that the analyses would not be performed. The licensee determined that further review efforts for past significance of these issues was not justified.

The licensee obtained information on at least two occasions prior to issuance of the LER that should have alerted them to the problem. First, a 1976 letter from Babcock and Wilcox (B&W) informed Toledo Edison that B&W had no data regarding design basis accident testing for particular coatings. The equipment coated with unqualified paint identified in the letter included the reactor coolant pump motors, reactor vessel, steam generators, pressurizer, and reactor coolant system piping. Second, NRC Generic Letter 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment," dated July 14, 1998, was issued to operating reactors requesting information about the potential effects of containment coating deficiencies. The licensee initiated several Condition Reports (CRs) to address this issue, including CR 03-01718, “Update Response to Generic Letter 98-04; Protective Coatings in Containment,” CR 03-03609, “Component Protective Coatings Not DBA Qualified,” and CR 02-02846, “Containment Emergency Sump Issues.”

Analysis:

Phase 1 Screening Logic, Results and Assumptions

In accordance with IMC 0612, Appendix B, the inspectors determined that the issue was of more than minor safety significance because if left uncorrected, it could become a more significant safety concern. The potential loss of low pressure recirculation due to sump strainer clogging represents a potential loss of the mitigation for medium and large sized LOCAs.

In accordance with IMC 0609, Appendix A, Attachment 1, the inspectors performed a SDP Phase 1 screening and determined that the issue affected the Mitigation Systems Cornerstone. Specifically, the issue represented an actual loss of a safety function (i.e., low pressure recirculation), thus an SDP phase 2 analysis was required. The actual loss of low pressure recirculation was assumed to occur upon initiation of sump recirculation following a medium or large LOCA.

Phase 2 Risk Evaluation

In accordance with IMC 0609, Appendix A, Attachment 1, the inspectors performed a SDP phase 2 analysis using Revision 1 to the licensee's site specific risk-informed inspection notebook. Only the worksheets for medium and large LOCA were evaluated because it was assumed that these were the only initiating events that could result in the transfer of unqualified coatings and other debris to the containment sump. During the Phase 2 evaluation, the inspectors assumed that there was a total loss of low pressure recirculation (i.e., loss of LPR function) caused by the loss in net positive suction head (NPSH) to the low pressure injection pumps. The loss of NPSH was assumed to be the result of paint and other debris (e.g., piping insulation) clogging the containment sump intake strainer. This condition existed for greater than 30 days and no credit was given for recovery of the clogged strainer.

Based on the Phase 2 SDP results, the issue was determined to be RED, which is of high importance to safety. This preliminary finding represents a change in the core damage frequency of greater than 1E-4 per reactor year of operation (MLOCA - Medium Loss of Coolant Accident).

Comparisons with the licensee's risk model indicated that the licensee's frequencies for the medium and large LOCAs are about one order of magnitude lower than that assumed in the SDP Phase 2 result. The licensee used the initiating event frequencies identified in NUREG/CR-5750, Rates of Initiating Events at U.S. Nuclear Power Plants, which is commonly used in most licensee PRAs. Differences in the LOCA initiating event frequencies result in the worksheets being somewhat conservative by about one order of magnitude.

Phase 3 Risk Evaluation

SPAR Analysis

Revision 3i of the Davis-Besse SPAR model was used for the SPAR analysis. When the conducting the analysis, there were three primary considerations. The first was the determination of which accident types to consider. The analysis was consistent with the SDP Phase 2 approach in that only the medium and large LOCAs were considered as a primary means for transporting paint and other debris to the containment sump. Other than the forces and environmental conditions that would occur during the LOCAs, the actuation of containment spray was also considered as a means to transport the debris to the containment sump. It was assumed that containment spray would actuate during the medium and large LOCAs. Although it does not appear reasonable that small LOCAs and other transients should be considered in the analysis due to the lack of debris transport to the sump, all accidents requiring the use of high pressure recirculation (i.e., piggyback mode of ECCS operation) were considered.

The second consideration was determination of the appropriate failure probability of the sump. The basic event of interest in the SPAR model is named “HPR-SMP-FC-SUMP and has a failure probability of 5E-5. The licensee’s value is 2.2E-5. Based on the increased likelihood of sump clogging due to the performance deficiency, these probabilities were not considered to be appropriate. The SPAR model probability was therefore adjusted based on information provided in NUREG/CR-6771, GSI-191, The Impact of Debris Induced Loss of ECCS Recirculation on PWR Core Damage Frequency. This NUREG was appropriate for this analysis because it studied the performance of an industry wide cross section of PWR containments and the Davis-Besse containment is within the bounds of this study. This NUREG suggests much higher failure probabilities for the sump than used in previous PRA studies. Numerous factors were considered in the GSI-191 study which have an impact on the failure probabilities postulated. These factors include such information as sump strainer surface area, NPSH margin, ECCS flow rates, containment spray actuation setpoint, amount of insulation material in containment, etc. For this analysis, however, no attempt was made to vary the qualitative failure probabilities described in Table 4.1 of GSI-191 based on plant specific information at Davis-Besse. Rather, failure probabilities from Table 4.1 were assigned based on a qualitative understanding of the increased likelihood of sump clogging due to the large amount of unqualified coatings in containment, the as-found degraded condition of peeling coatings, and the transfer of those coatings and other debris to the sump during the accidents evaluated. Therefore, for the purposes of this analysis, a failure probability of 0.9 was used for the best estimate result for the large LOCA. This probability is considered as a “likely” occurrence in GSI-191. For the medium LOCA, a failure probability of 0.5 was selected. This probability is considered “fully possible.” For small LOCAs and other transients, a sump failure probability of 0.1 was used. This probability is characterized as “unlikely” in GSI-191. Note that these probabilities are several orders of magnitude higher than the nominal failure probability in the SPAR model and licensee’s data bases. This is considered conservative and is appropriate due to the lack of an actual transport analysis (The licensee has no plans to perform a detailed transport analysis which would likely refine some conservative assumptions made in this analysis). In order to bound the analysis, the loss of low pressure recirculation during medium and large LOCAs and loss of high pressure recirculation during small LOCAs and other transients was assumed to occur by adjusting the failure probability to "True" or 1.0 (guaranteed failure). These results are presented below.

The third consideration was whether recovery credit should be applied to the clogged sump strainer. During the event, it is reasonable to conclude that operators would become aware through annunciation and pump performance monitoring that a problem with the low pressure ECCS pumps had occurred. It is possible that operators could reduce flowrates or stop the pumps when indications of a loss of NPSH had occurred. However, without a thorough review of operating procedures and related training, it would be difficult to understand the probability of non-recovery of the loss or impending loss of low pressure injection during the recirculation phase of ECCS injection. Also, it is reasonable to conclude that operators may be hesitant to shutdown the low pressure injection pumps or reduce their flow under LOCA conditions, especially the large LOCA. Therefore, for this analysis, no credit was given for recovery of the clogged sump strainer on the loss of the low pressure injection pumps.

SPAR Analysis Results

The results below reflect the change in the core damage frequency from the base case model with the sump failure probability at 5E-5 subtracted from results with the sump failure probabilities as noted.

Best Estimate SPAR Analysis Results

Large LOCA (sump failure probability set to 0.9)
5.13E-10/hr x 8760 hrs = 4.50E-6

Medium LOCA (sump failure probability set to 0.5)
2.28E-9/hr x 8760 hrs = 2.00E-5

Other Accidents (e.g., small LOCA, transients, etc.) Requiring High Pressure Recirculation (sump failure probability set to 0.1)
2.15E-9/hr x 8760 hrs = 1.88E-5

Combined Large and Medium LOCA Results With Other Accidents
2.45E-5 + 1.88E-5 = 4.33E-5 (Yellow)

Based on the SPAR model results presented above, the finding is in the mid Yellow range of importance.

Bounding SPAR Analysis Results

Results with Sump Failure Probability Set to 1.0 for Both Medium and Large LOCAs
(5.70E-10/hr x 8760 hrs) + (4.57E-9/hr x 8760 hrs) = 4.50E-5

Results with Sump Failure Probability Set to 1.0 for Other Accidents Requiring High Pressure Recirculation
2.64E-8/hr x 8760 hrs = 2.31E-4

Combined LOCA Results with Other Accidents
4.50E-5 + 2.31E-4 = 2.76E-4 (RED)

<u>RAW Calculation (provided by licensee)</u>

Davis-Besse baseline CDF = 1.22E-5/yr (includes internal plant flooding)
RAW value for failure of sump strainer for large and medium LOCAs = 1.41 and 4.27 respectively. RAW value for small LOCA and all other accidents = 9.18

1.22E-5/yr x 1.41 (LLOCA RAW) = 1.72E-5/yr
1.72E-5/yr - 1.22E-5/yr = 5.00E-6/yr (delta CDF for LLOCA)

1.22E-5/yr x 4.27 (MLOCA RAW) = 5.21E-5/yr
5.21E-5/yr - 1.22E-5/yr = 3.99E-5/yr (delta CDF for MLOCA)

1.22E-5/yr x 9.18 (SLOCA and Other Accidents) = 1.12E-4
1.12E-4/yr - 1.22E-5/yr = 9.98E-5/yr (delta CDF for SLOCA and Other Accidents)

Total Delta CDF for All Accidents
5.00E-6/yr + 3.99E-5/yr + 9.98E-5/yr = 1.45E-4 (RED)

Although the total delta CDF is in the low RED range of importance assuming a complete failure of the containment sump under all conditions requiring low and high pressure recirculation, this result is not representative of the significance of the finding. As mentioned earlier, the likelihood of debris transport during a small LOCA and during other accidents is much less likely. This bounding analysis provides the worst possible result using the PRA results provided by the licensee and those in the SPAR model. Note that the results from both the SPAR model and licensee model are very similar. This similarity provides a validation of the results and provides reasonable assurance of the significance of the finding when making the assumptions presented.

<u>Internal Flooding</u>

Internal plant flooding is a relatively low contributor to the total CDF. The IPE states that the overall contribution is about 3%. Since the IPE submittal, the updated overall Davis-Besse PRA model results have been reduced, therefore the current internal flooding contribution is about 15% of the total CDF. A large percentage of this risk is associated with flooding and subsequent failure of all service water or component cooling water pumps resulting in a LOCA condition due to failure of the reactor coolant pump seals. Given that a seal failure and subsequent small LOCA occurs, the need for feed and bleed requires the use of high pressure recirculation to maintain the core cooled. When feed and bleed is placed in service, the resulting letdown of coolant inventory is drained to the containment sump. As discussed previously, this mechanism of debris transport is not as likely as during medium and large LOCAs. Based on the relatively low contribution from internal flooding and the lower likelihood of debris transport during feed and bleed operation, it is judged that the impact from flooding is not significant and would not change the overall significance of the finding.

<u>Summary for Internal Events Analysis</u>

The results of the SDP Phase 2 are conservative because the initiating event frequencies for LOCAs assumed in the site specific notebook are higher by about one order of magnitude than the license's results. If these frequencies are adjusted to coincide with the licensee's frequencies, which are consistent with NUREG/CR-5750, the SDP Phase 2 result would be in the Yellow range of importance. This result would then match the SPAR analysis result and the RAW values provided by the licensee. Because the licensee did not perform a transport analysis, it is appropriate to use conservative failure probabilities for sump failure. The values chosen in the SPAR analysis are significantly higher than the base case value in the both the licensee's PRA model and the SPAR model. Increasing the sump failure probability from the 1E-5 range to the 1E-1 range and higher is appropriate due to the lack of information regarding the transport of coatings and debris to the containment sump. In addition, the information discussed in GSI-191 indicates that sump failure is likely to be more important than previously analyzed.

The primary contributing events leading to the transport of debris and paint to the containment sump are the medium and large LOCAs. Other accidents were considered, such as small LOCAs and transients where high pressure recirculation is needed to prevent core damage. Assuming a conservative failure probability of 0.1 for these accidents resulted in an increase in the core damage frequency in the Yellow range of importance using the revised SPAR model. When this result was added to the primary LOCA contributors, the result remained in the Yellow range of importance.

Although recovery of low pressure recirculation was not considered in this analysis, the results would likely not decrease below the Yellow range of importance because the non-recovery failure probability would likely be very high (greater than 0.5). Applying this 0.5 non-recovery factor to the calculated SPAR model result would still result in the finding being in the Yellow range (4.33E-5/yr x 0.5 = 2.17E-5 - Yellow) .

It is estimated qualitatively that there is approximately one order of magnitude of uncertainty with the final outcome of this analysis. The most uncertain aspect of the evaluation is the failure probability of the sump during the various accident types. Because the licensee did not perform a transport analysis, high probabilities for sump failure were used. As discussed earlier, this is appropriate for the purposes of the SDP process. As presented in the SPAR model sensitivity calculations, the finding is in the Yellow range of importance. This overall importance could be reduced given credit for recovery. It is judged, however, that even if a non-recovery probability of 0.1 was applied that the overall result would not reduce beyond one order of magnitude. Given the performance deficiency related to the unqualified coatings and other debris and recent information presented in GSI-191, the relatively high sump failure probabilities are appropriate. The overall results of this analysis would be reduced significantly if the sump failure probability was significantly less than assumed in this analysis.

Potential Risk Contribution due to LERF

The impact of strainer clogging and subsequent loss of low pressure recirculation and high pressure recirculation is not a significant contributor to LERF.

Potential Risk Contribution due to External Events

IMC 609, Appendix A, Attachment 1, requires that that when any of the SDP Phase 2 sequence result is greater than 1E-7 per year, that the finding be evaluated for additional risk due to external event contribution. The evaluation may be qualitative or quantitative. Considering the information reviewed from the plant's IPEEE and related documents, accounting for external events does change the conclusion that the finding is Yellow.

Conclusion

The preliminary safety significance of the inspection finding based on the change in CDF due to internal, external and LERF considerations is Yellow. A Yellow finding is of substantial importance to safety

Enforcement: The performance deficiency is the licensee's failure to effectively implement corrective actions for design control issues related to deficient containment coatings, uncontrolled fibrous material and other debris. This deficiency resulted in the inability of the emergency core cooling system sump to perform its safety function under certain accident scenarios due to clogging of the sump screen. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," requires, in part, that measures shall be established to assure that conditions adverse to quality such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and 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 is taken to preclude repetition. Contrary to the above, the licensee failed to effectively implement corrective actions for design control issues related to deficient containment coatings, uncontrolled fibrous material and other debris. Pending determination of the finding's final safety significance, this finding is identified as Apparent Violation (AV) 50-346/03-015-05.

4OA5 Other Activities

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;
- 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 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 area:

- performance of plant activities, including maintenance activities;
- follow-up of specific Oversight Panel Technical issues;
- attended and assessed selected licensee restart readiness meetings;
- evaluated licensee performance in categorizing, classifying, and correcting deficient plant conditions during the restart process;
- reviewed licensee controls, criteria, and assessed licensee performance at meetings associated with work backlogs, including the deferral of work orders, operator work arounds, temporary modifications, and permanent modifications; and
- reviewed activities associated with safety conscious work environment and safety culture.

The following issues were evaluated during this inspection period.

.1 Inappropriately Lowering Shutdown Risk Category During Reduced Inventory Operations

While refilling and prior to venting the reactor coolant system after reactor coolant pump seal package resistance temperature detector work, the licensee incorrectly and inadvertently lowered the risk category from orange (marginal shutdown safety) to Yellow (adequate shutdown safety). This lowering of the risk category permitted stopping some of the contingency plan actions that were in place for the orange risk condition. The inadvertent lowering of the classification was not safety significant because of the short time that the condition existed and all decay heat trains remained available.

During the week of June 8, 2003, the licensee made preparations to drain the reactor coolant system water level to 54 inches above the hot leg centerline for repair of leaks from resistance temperature detectors located in the mechanical seal packages of the reactor coolant pumps. In accordance with their procedures, the licensee analyzed the risk of the draining evolution and determined that during a portion of the evolution, the risk would transition from the existing Yellow category to the higher orange category. The licensee developed a contingency plan for management actions during initial draining activities and draining below 80 inches. The contingency plan required, during orange risk configurations, various items including protecting from unnecessary work both trains of decay heat removal equipment. If work were permitted in the rooms housing decay heat removal equipment, the contingency plan also required than an operator had to be present in those rooms.

On June 13, 2003, at 9:53 a.m., management permission was given to enter orange risk during the drain. At 1:41 p.m. the plant activated the contingency plan for orange risk condition. On June 14, 2003, at 5:03 p.m. the drain to 54 inches was completed. On June 15, 2003, at 5:27 p.m. the reactor coolant system had been refilled to 80 inches. At that time a log entry records that due to commencing the fill to 250 inches in the pressurizer, the plant exited the orange risk category and entered Yellow risk. On June 16, 2003, at approximately 5:00 a.m., it was determined that the plant should have remained in an orange risk category and, at 7:45 a.m., the orange risk contingency action plan was reestablished. During the period that orange risk condition was required but was not established, one decay heat train had been made unprotected from unnecessary work. The licensee documented the incorrect application of risk in a condition report. At 4:40 p.m., the licensee had completed all actions to exit from the orange risk condition and return to the Yellow risk condition.

Because of lack of clear directions to the operating shifts and a shutdown risk procedure with some provisions clearly understood only by a limited number of operations personnel, the operations shift, on June 15, 2003, exited orange risk conditions, contrary to existing procedural requirements, for a period of approximately 14 hours. For a period of that time, contingency plan requirements, designed to minimize the potential to lose shutdown cooling during the elevated risk condition, were relaxed.

.2 Negative Trend in the Number of Engineering Change Request Administrative Errors

On June 28, 2003, the licensee wrote condition report (CR) 03-05092 to document that numerous administrative deficiencies had been discovered during document management's acceptance review of engineering change packages and to provide a mechanism to review a trend of deficiencies. The CR listed 25 other CRs that were written to document administrative deficiencies.

The inspectors separately conducted a review of the CR system for identified discrepancies in engineering change requests. The intent of the review was to verify that there were not other adverse trends associated with engineering change requests and to verify that the licensee had properly characterized the adverse trend. The review identified 25 condition reports, covering the period of October 25, 2002 through June 25, 2003, that identified problems in engineering change packages. Many of the licensee identified CRs were the same as those independently identified by the inspectors. The majority of the problems identified were administrative in nature and were judged by the inspectors to indicate a lack of attention to detail in the existing process as detailed in licensee procedures. The inspectors did not identify any condition report in which the documented error had impacted a design change had been installed and accepted in the plant.

The inspectors did identify that CR 02-08642 had identified, on October 25, 2002, administrative errors in the engineering change process after implementation of a process change in the design interface review. The CR stated that the issue was already being addressed through the completion of lesson learned training identified in CR 02-09694. The inspectors met with licensee representatives to review similarities between the new trend and the previously identified issue and, if the conditions were similar, the impact of the lesson learned training. That licensee stated that the problem identified in CR 02-08642 was directly related to the implementation of a then recent process change and the formulated corrective action was not targeted to generic administrative errors as identified in the CR 03-05092.

Administrative errors in engineering change packages have been identified in condition reports as an recurring problem. Recurring administrative errors can be an indicator of inattention to detail which may extend beyond just administrative details. The licensee had indications of ongoing administrative problems prior to the initiation of CR 03-05092, but until this CR reviewed many of identified problems as independent events.

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

The resident inspectors continued to monitor the licensee 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 4 and 3 restraints;
- evaluated the licensee classification of emergent deficient conditions; and
- evaluated closed mode restraints.

As part of this inspection, the inspectors attended selected Corrective Action Review Board meetings, Senior Management Team meetings, Scheduling meetings, Management Review Board meetings, and Restart Oversight meetings, where classification of condition reports, prioritization of work activities, and setting of work completion dates took place. The inspectors also evaluated a sampling of completed Mode 4 and Mode 3 resolution forms.

No significant issues were identified.

.4 Safety Conscious Work Environment (SCWE) and Safety Culture Observations

The inspectors continued to evaluate, on a day-to-day basis, the impact that scheduling has on quality of work and safety conscience work environment. The inspectors performed this evaluation when they attended the following meetings:

- Emergency Diesel Generator (EDG) air start modification scheduling meeting, June 5, 2003; and
- Safety Conscious Work Environment Review Team, June 12, 2003.

No significant issues were identified.

4OA6 Meetings

Exit Meeting

The inspectors presented the inspection results to Mr. Lew Myers, and other members of licensee management on July 9, 2003. The licensee acknowledged the findings presented. No proprietary information was identified.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance was identified by the licensee and is a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Manual, NUREG-1600, for being dispositioned as a NCV.

- Technical Specification 6.8.1.a requires implementation of procedures required by Regulatory Guide 1.33. Regulatory Guide 1.33 requires procedures for maintenance which can affect the performance of safety-related equipment. The licensee developed Procedure DB-MN-00001, “Conduct of Maintenance,” Revision 10, a procedure affecting quality, to provide general guidance for the conduct of maintenance at the Davis-Besse facility. Additionally, the licensee developed Procedure DB-MM-09173, “High Pressure Injection Pump Maintenance,” Revision 04, which provided instructions for the disassembly, inspection, cleaning, repair, and reassembly of the high pressure injection pumps. Contrary to the requirements of DB-MN-00001, step 6.1.6.a, the calibration of the equipment utilized to torque the casing bolt nuts for the high pressure injection pump 1 was not checked prior to use. As a result, during the performance of DB-MM-09173, step 8.7.57, the desired torque on the casing bolt nuts was exceeded by approximately 77 ft-lbs. This issue has been entered into the licensee’s corrective action program (CR 03-04430). This issue was also discussed in Section 1R12 of this report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

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KEY POINTS OF CONTACT

Licensee Personnel

M. Bezilla, Site Vice President
G. Dunn, Outage Manager
R. Fast, Director, Organizational Development
J. Grabnar, Manager, Design Engineering
K. Ostrowski, Manager, Regulatory Affairs
L. Myers, Chief Operating Officer, FENOC
J. Powers, Director, Nuclear Engineering
M. Roder, Manager, Plant Operations
R. Schrauder, Director Support Services
M. Stevens, Director, Maintenance

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-346/03-015-04	URI	Potential Inability for HPI Pumps to Perform Safety Related Function
50-346/03-015-05	AV	Failure to Effectively Implement Corrective Actions for Design Control Issues Related to Deficient Containment Coatings, Uncontrolled Fibrous Material and Other Debris

Opened and Closed

50-346/03-015-01	NCV	Failure to Provide Adequate Procedural Guidance for Tightening Fasteners Internal to the High Pressure Injection Pump
50-346/03-015-02	NCV	Failure to Perform Work in Accordance With Approved Maintenance Procedures During the Installation of Reactor Coolant Pump Mechanical Seal RTDs
50-346/03-015-03	NCV	Failure to Properly Implement System Procedures During the Filling of the Circulating Water System

Discussed

50-346/03-002	LER	Potential Degradation of High Pressure Injection Pumps Due to Debris in Emergency Sump Fluid Post Accident
50-346/02-005-00 50-346/02-005-01 50-346/02-005-02	LER	Potential Clogging of the Emergency Sump Due to Debris in Containment

LIST OF ACRONYMS

ADAMS	Agency-wide Document Access and Management System
B&W	Babcock & Wilcox
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CR	Condition Report
CS	Containment Spray
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
FENOC	FirstEnergy Nuclear Operating Company
HPI	High Pressure Injection
ICM	Interim Compensatory Measures
IMC	Inspection Manual Chapter
IPE	Individual Plant Examination
IR	Inspection Report
LER	Licensee Event Report
LERF	Large Early-release Frequency
LOCA	Loss of Coolant Accident
MLOCA	Medium LOCA
NCV	Non-cited Violation
NPSH	Net Positive Suction Head
NRC	United States Nuclear Regulatory Commission
PARS	Publicly Available Records
PRA	Probabilistic Risk Assessment
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RFO	Refueling Outage
RTD	Resistance Temperature Detector
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
TI	Temporary Instruction
TS	Technical Specifications
URI	Unresolved Item
USAR	Updated Safety Analysis Report
WO	Work Order

LIST OF DOCUMENTS REVIEWED

1R01 Adverse Weather Protection

DB-OP-06913; Seasonal Plant Preparation Checklist, Revision 06

DB-OP-00005; Special Instructions and Expressions, Zone 1 Operations Tours; Revision 8

1R05 Fire Protection

Fire Hazards Analysis Report

Fire Protection Drawings A-221F, A-222F, A-223F, A-224G,

1R12 Maintenance Effectiveness

High Pressure Injection Pump Night Shift Turnover Dated June 6, 2003

CR 03-04430 Cause Analysis Report; Use of Non-Calibrated Tools on HPI Pump 1

CR 03-04430; Use of Uncalibrated Tools

Order 200010574; Disassemble/Remove #1 HPI Pump Internals. Prepare for Shipment to Vendor. Reassemble Pump With Replacement Rotating Element

DB-MN-00001; Conduct of Maintenance; Revision 10

DB-MM-09173; High Pressure Injection Pump Maintenance; Revision 04

CR 03-04278; Broken Bolting Found in High Pressure Injection Pump #1

CR 03-04279; FME Inside #1 HPI Pump

CR 03-04355; HPI Pump Internal Head Cover Shoulder Cap Screws

DB-MM-09173; High Pressure Injection Pump Maintenance; Revision 02

DB-MM-09173; High Pressure Injection Pump Maintenance; Revision 04

CR 03-04773; RCP RTD Installation Not in Accordance With Vendor Manual

Order 200000263; Rework the RTD/TC Connections (as required) for all three stages of the RCP (1-1) Mechanical Seal

Order 200000274; Rework the RTD/TC Connections (as required) for all three stages of the RCP (1-2) Mechanical Seal

Order 200000279; Rework the RTD/TC Connections (as required) for all three stages of the RCP (2-1) Mechanical Seal

Order 200000294; Rework the RTD/TC Connections (as required) for all three stages of the RCP (2-2) Mechanical Seal

NG-DB-00225; Procedure Use and Adherence; Revision 12

DB-MN-00001; Conduct of Maintenance; Revision 10

DB-DP-00007; Control of Work; Revision 04

CR 03-0479; Leaking RTD on RCP 2-1

Problem Solving Plan for RCP RTD Leakage; dated 6/19/03

1R13 Maintenance Risk and Emergent Work

Contingency Plan 13RFO-32; All Source Range Nuclear Instruments Unavailable for Testing; Revision 0

Unit Narrative Log; Dated 5/23/03

NOP-OP-1005; Shutdown Safety; Revision 3

Operations Directive GP-27; Shutdown Safety Assessment; Revision 2

Form NOP-OP-1005-02; Shutdown Safety Turnover Checklist; dated 6/3/03

Contingency Plan 13 RFO 21; Management Action for Orange Risk Level During Initial RCS Draining Activities and Draining Below 80 Inches and Above 54 Inches; Revision 1

Davis-Besse Shutdown Safety Turnover Checklist; dated 6/13/03

Form NOP-OP-1005-02, Shutdown Safety Turnover Checklist; dated 6/16/03, 0500

Condition Report 03-04735; Plant Shutdown Safety Inadvertently Changed to Yellow

Unit Narrative Log; dated 6/13/2003 to 6/16/2003

1R14 Personnel Performance During Nonroutine Plant Evolutions

DB-OP-01002; Component Operation and Verification; Revision 00

DB-OP-00000; Conduct of Operations; Revision 06

DB-OP-06232; Circulating Water System and Cooling Tower Operation; Revision 05

DBBP-OPS-0001; Operations Expectation and Standards; Revision 04

Unit Narrative Logs dated 5/16/03

CR 03-03815; West Pit Flooding

Apparent Cause Investigation for CR 03-03815

Regulatory Applicability Determination 03-01124; HPI Pump 1 Mode 5 Enhanced Baseline Testing in Piggyback Mode; Revision 00

DB-SP-10030; HPI Pump 1 Mode 5 Enhanced Baseline Testing in Piggyback Mode; Revision 01

DB-OP-06012;Decay Heat and Low Pressure Injection System Operating Procedure, Revision 09

NG-DB-00201; Conduct of Infrequently Performed Tests and Evolutions, Revision 01

NG-DB-00201; Attachment 1; Pre-evolution or test activities briefing form completed by S. Wise; dated 6/14/2003

1R15 Operability Evaluations

Operability Evaluation 2002-0023; Revision 3

DP-OP-06513; Auxiliary Building Non-Radioactive Areas Ventilation

Operability Evaluation 2003-0009; Revision 01

Operability Evaluation 2003-0039; Revision 02

Past Operability Evaluation for CR 02-07596; LIR EDG High Room Temperatures Overall Condition Report

Root Cause Analysis Report; EDG Room Ventilation Concerns; dated 04/15/03

1R22 Surveillance Testing

DB-PF-0371 CCW Train 1 Valve Testing, Revision 06

Routine Maintenance WO 200002377 as existing on 6/23/2003

1R23 Temporary Plant Modifications

Temporary Modification 03-016; Install a Temporary Jumper to Pressurize EDG 2 Receiver 2-1 and Receiver 2-2 directly from EDG Air Compressor 2 During Cross-tie Piping Work

DB-OP-06316; EDG Operating Procedure; Revision 04

Piping and Instrument Diagram M-017B; Diesel Generator Air Start Piping; Revision 32

Temporary Modification 03-017, “Second Stage Seal Temperature on RCP1-2"

4OA3 Event Followup

CR 03-01718; Update Response to Generic Letter 98-04; Protective Coatings in Containment

CR 03-03609; Component Protective Coatings Not DBA Qualified

CR 02-02846; Containment Emergency Sump Issues

Root Cause Analysis Report;Non-DBA Qualified Protecftive Coatings Applied Within the Containment; dated 03/29/03

4OA5 Other Activities

CR 02-08642; Deficiencies identified in ECR 02-0658

CR 02-09694; EAB concerns with DIE process

CR-03-05092; Trending CR-engineering change packages

NOP-CC-2004; Design Interface Reviews and Evaluations, 6/2/2003