February 26, 2003

Mr. Lew 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 SPECIAL INSPECTION - SYSTEM HEALTH ASSURANCE - REPORTS
NO. 50-346/02-13(DRS) and 50-346/02-14(DRS)

Dear Mr. Myers:

On November 13, 2002, the NRC completed a special inspection at your Davis-Besse Nuclear Power Station. This inspection reviewed your actions to resolve Restart Checklist Item No. 5.b, associated with assuring the capability of safety significant structures, systems and components to support safe and reliable plant operation. Specifically, this inspection focused on review of activities as described in the "Davis-Besse System Health Assurance Plan." The plan consisted of three review programs: an Operational Readiness Review (ORR), a System Health Readiness Review (SHRR), and a Latent Issues Review (LIR). Our inspection of this plan included reviewing the plans and procedures for the ORR, SHRR, and LIR, monitoring the work of the SHRR and LIR teams in-progress, monitoring Nuclear Oversight activities, attending review board meetings, and reviewing Condition Reports generated by the teams as reviews were conducted and discrepancies were identified. The inspectors also monitored training of reviewers, conducted walkdowns of selected systems, examined emergent issues, reviewed independent self-assessments of systems, and reviewed two SHRR reports. In addition, to assess the quality of your staff's reviews, the NRC conducted an in-depth design and performance capability review of the Service Water, High Pressure Injection, and 4160 Volt AC Electrical Distribution systems. The enclosed reports document the findings of this special inspection, which were discussed with you and other members of your staff during an exit meeting on November 13, 2002.

Report No. 50-346/02-13(DRS) discusses the review of the plans, procedures, and implementation of the System Health Assurance Plan. No violations of NRC rules or regulations were identified. The inspectors concluded that the System Health Assurance Plan was well-designed, plans and procedures were appropriate to the circumstances, the program was rigorously implemented, and quality assurance review by the Nuclear Oversight Department was adequate. At the close of the inspection, only two of the 36 anticipated review reports had been completed. The inspectors reviewed the System Health Readiness Review Report for the 125/250 Volt DC Electrical Distribution system and concluded that the review had been performed acceptably.

Report No. 50-346/02-14(DRS) discusses the in-depth design and performance capability review of the Service Water, High Pressure Injection, and 4160 Volt Electrical Distribution systems. The inspectors identified four findings, one with multiple examples, of very low safety significance (Green) that were determined to involve violations of NRC requirements. The first finding involved failure to complete Technical Specification surveillance requirement 4.2.5.H, associated with High Pressure Injection pump flow following modifications that could alter system flow characteristic. The second finding involved examples of failure to assure that applicable regulatory requirements and the design basis for structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions related to a non-conservative TS value for the 90 percent degraded voltage relay, a non-conservative relay setpoint calculation for the 59 percent undervoltage relay, an inadequate analytical basis for the setpoint to swap the service water system discharge path, a lack of a design basis analysis for containment isolation valve backup air supply accumulators, and inadequate blowdown provisions for Containment Air Cooler backup air accumulators. The third finding involved a service water surveillance test that did not use worst case values to bound the design basis conditions. The fourth finding involved failure to take prompt corrective actions for incorrect service water pump discharge check valve test acceptance criteria. In addition, the inspectors identified seventeen issues where design control may have been inadequate; however, at the close of the inspection, insufficient information was available to draw a conclusion regarding the acceptability of these items which are identified as unresolved items in the report. Additional analyses, in most cases by your staff, are necessary to generate the information needed to resolve the issues.

Because of the very low safety significance of the findings and because these issues have been entered into your corrective action program, the NRC is treating these issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny these Non-Cited Violations, you should provide a response with a basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Davis-Besse Nuclear Power Station.

The results of our review of the Service Water system were consistent with your Latent Issues Review and a corporate Nuclear Oversight self-assessment. All three efforts identified a significant number of deficiencies in calculations, analyses, and testing which will require resolution prior to restart. We are also aware that the Latent Issues Reviews on the component cooling, emergency diesel, auxiliary feedwater, and reactor coolant systems identified similar deficiencies. As a result of these findings, we have concluded that the Latent Issues Reviews were performed in a manner sufficient to reasonably determine whether or not systems were capable of performing their safety functions during future plant operation.

Because the majority of the System Health Assurance Plan reports were not ready for review by the close of the inspection and because the findings of the Latent Issues Review program dictate the need to expand the scope of system reviews, Restart Checklist item 5.b will remain open and subject to continued inspection.

In accordance with 10 CFR Part 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

Enclosures:
1. NRC Special Inspection Report No. 50-346/02-13(DRS)
2. NRC Special Inspection Report No. 50-346/02-14(DRS)

cc w/encls:
B. Saunders, President - FENOC
Plant Manager
Manager - Regulatory Affairs
M. O'Reilly, FirstEnergy
Ohio State Liaison Officer
R. Owen, Ohio Department of Health
Public Utilities Commission of Ohio
President, Board of County Commissioners
  Of Lucas County
President, Ottawa County Board of Commissioners
D. Lochbaum, Union of Concerned Scientists

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/RA/

John A. Grobe, Chairman
Davis-Besse Oversight Panel

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

Enclosures: 1. NRC Special Inspection Report
No. 50-346/02-13(DRS)
2. NRC Special Inspection Report
No. 50-346/02-014(DRS)

cc w/encls: B. Saunders, President - FENOC
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Manager - Regulatory Affairs
M. O'Reilly, FirstEnergy
Ohio State Liaison Officer
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Public Utilities Commission of Ohio
President, Board of County Commissioners
Of Lucas County
President, Ottawa County Board of Commissioners
D. Lochbaum, Union of Concerned Scientists

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ENCLOSURE 1

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-346
License No:	NPF-3
Report No:	50-346/02-013
Licensee:	FirstEnergy Nuclear Operating Company
Facility:	Davis-Besse Nuclear Power Station
Location:	5501 North State Route 2 Oak Harbor, OH 43449
Dates:	September 3 through November 13, 2002
Inspectors:	M. Farber, Senior Reactor Inspector J. Jacobson, Senior Mechanical Engineer G. Hausman, Senior Reactor Inspector
Approved by:	Ronald N. Gardner, Chief Electrical Engineering Branch Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000346-02-013; FirstEnergy Nuclear Operating Company; on 09/03-11/08/02; Davis-Besse Nuclear Power Station. System Health Assurance Plan Implementation Inspection

The report covers a special inspection, by three regional inspectors, of the Davis-Besse Nuclear Power Station System Health Assurance Building Block. 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. Inspector Identified Findings

None

B. Licensee Identified Findings

None

REPORT DETAILS

4. OTHER ACTIVITIES

4OA3 Event Follow-up (93812)

Background

On March 6, 2002, Davis-Besse personnel notified the NRC of degradation (corrosion) of the reactor vessel head material adjacent to a control rod drive mechanism (CRDM) nozzle. This condition was caused by coolant leakage and boric acid corrosion of the head material induced by an undetected crack in the adjacent CRDM nozzle. The degraded area covered in excess of 20 square inches where the low-alloy structural steel was corroded away, leaving the thin stainless steel cladding layer. This condition represented a loss of the reactor vessel's pressure retaining design function, since the cladding was not considered as pressure boundary material in the structural design of the reactor pressure vessel. While the cladding did provide a pressure retaining capability during reactor operations, the identified degradation represented an unacceptable reduction in the margin of safety of one of the three principal fission product barriers at the Davis-Besse Nuclear Power Station (reference NRC report 50-346/02-03(DRS)).

The System Health Assurance (SHA) Plan is one of seven building blocks identified as part of the licensee's Return to Service Plan. The intent of the SHA plan was to review plant systems prior to restart to ensure that these systems were in a condition that would support safe and reliable information. The plan consisted of three review programs: an Operational Readiness Review (ORR), a System Health Readiness Review (SHRR), and a Latent Issues Review (LIR). NRC inspectors reviewed the activities as described in the SHA plan. Given the high public interest in this subject area at Davis Besse, and therefore the need to clearly communicate the rationale for NRC staff conclusions regarding the effectiveness of licensee extent of condition inspections, this report documents the inspectors' observations.

a. Inspection Scope

The inspectors reviewed the plans and procedures for the ORR, SHRR, and LIR, monitored the work of the SHRR and LIR teams in-progress, monitored Nuclear Oversight activities, attended review board meetings, and reviewed Condition Reports (CR) generated by the teams as reviews were conducted and discrepancies were identified. The inspectors also monitored training of reviewers, conducted walkdowns of selected systems, examined emergent issues, reviewed independent self-assessments of systems, and reviewed two SHRR reports.

b. Observations and Findings

b.1 Operational Readiness Reviews

a. Introduction

The inspectors examined the Operational Readiness Review (ORR) program, CRs issued as a result of the reviews, and the final ORR report.

b. Description

The licensee initiated the ORR program before the NRC implemented the Manual Chapter 0350 process for Davis-Besse. The licensee developed this program to ensure that selected systems and programs were in a condition that would support safe and reliable plant operation through the forthcoming operating cycle (cycle 14) and beyond. The ORR was initiated by the Plant Manager and consisted of a panel composed of system engineers and representatives of other site organizations. Forty-one systems and eight programs were selected for review, based on risk significance, Maintenance Rule performance, materiel condition, and operator burden. The ORRs were patterned on the licensee's Quarterly System Health Report and covered the selection criteria plus significant issues or corrective actions, mode restraints, latent issues, and operating experience.

ORRs were nearly completed when the SHA plan was in development. The ORR was incorporated into the SHA plan to ensure that all system review efforts were captured under one program, that findings were retained and properly documented, and that appropriate corrective actions were specified. After the reviews were completed, a CR was generated by the Quality Assurance (QA) Department documenting concerns with the administration and tracking of action items identified during the ORR. Subsequently, a rigorous validation program for ORR was conducted to ensure that the program was adequately documented, that new issues or changes were identified, and that issues were entered into the corrective action program. Forty-two CRs were generated which listed the issues and related outstanding corrective actions for 40 systems and two programs.

c. Observations and Findings

No findings were identified. The ORR was a proactive effort at system assessment. The concept of a multi-disciplined panel consisting of management and supervisory personnel reviewing the system engineer's analysis of system condition was well-conceived. While the system engineers' analyses and panel reviews appeared thorough, the project lacked rigor in the recording, tracking, and statusing of issues and action items which were identified by the program. The QA condition report (02-02941) noted that action items were not documented in CRs, that action items were overdue, with no formal tracking mechanism to ensure completion, and that ORR action items were not screened for inclusion in the Restart Action List. The subsequent validation effort identified issues that were not evident in the original ORR. The validation effort introduced the necessary rigor to the documentation process and resulted in a complete, concise tabulation of issues.

b.2 System Health Readiness Reviews

a. Introduction

The inspectors reviewed the plans and procedures for SHRRs, reviewed the charters for the various panels and boards established to oversee the SHA plan, monitored reviews in progress, interviewed reviewers, examined scoping and testing memos, walked down systems, observed meetings of the Engineering Assessment Board, Restart Station Review Board, and Restart Senior Management Team, reviewed CRs that were related to SHRRs, and examined emergent issues, i.e., issues not directly related to SHRR, but identified as a result of walkdowns or examining SHRR documents.

b. Description

b.2.1 Procedure and Process

SHRRs were performed for 31 systems categorized as risk-significant under the licensee's Maintenance Rule program. The intent of SHRRs was to assess the material condition of the systems and to determine whether process or programmatic issues existed that could potentially have an adverse impact on system operability or functionality. Five, more risk-significant systems were reviewed under the LIR program which will be discussed later in this report. SHRRs were conducted using procedures EN-DP-01503, System Walkdown, and EN-DP-01504, System Health Readiness Review. Revisions to these procedures were issued during the course of reviews; these revisions are listed at the end of this report.

The inspectors reviewed both procedures noted above, along with the charters for the Engineering Assessment Board, Restart Safety Review Board, and Restart Senior Management Team. EN-DP-01503, System Walkdown, provided a structured process for conducting system walkdowns and recording deficiencies, and provided lists of potential problems and conditions as criteria for identifying deficiencies. EN-DP-01504, System Health Readiness Review, provided training requirements, documents to be reviewed, a structure and process for defining the scope of the reviews, establishing the testing necessary to support safety functions, selecting data sources and conducting data source reviews, criteria and process for expanding the review scope, and preparation, review, and approval of the final report.

c.2.1 Observations and Findings

No findings were identified. The inspectors determined that both procedures were well-written, logical, complete, and appropriate to the circumstances. One minor procedural problem was identified. The inspectors learned from interviews, CRs, and schedule reviews, that walkdowns and document reviews were being conducted in parallel with the development of the scoping and testing letters. There was no formal mechanism in the SHRR procedure to ensure that changes mandated by EAB to either the scoping or testing memoranda would be reflected back into the walkdowns or document reviews. This resulted in the potential that approved changes might not be completely reviewed. The licensee issued a procedure revision to address this issue. No other problems were identified.

b.2.2 Training

Requirements for training SHA reviewers were specified in the SHRR procedure. This training covered system design and licensing basis, site-specific databases, Generic Letter 91-18 (Operability Determinations), the system walkdown procedure, FirstEnergy Principles and Expectations, and the system health readiness review process.

The inspectors reviewed training records, met with instructors, and attended a training session for reviewers.

c.2.2 Observations and Findings

No findings were identified. The inspectors considered the training provided for SHA reviewers to be well-developed, adequately administered, and appropriate to the circumstances. Training records were properly maintained, and documented the training and qualification of all SHA reviewers. Through the combination of interviews and attending training sessions, the inspectors determined that instructors were qualified, knowledgeable of the SHA program, and well-prepared to lead the training sessions.

During one training session, the inspector observed that several class members were apparently disinterested and not paying attention. At the end of the session, when the instructor was questioning the class to assess the level of retention, these individuals were unable to answer the instructor's questions. The inspector brought this to the attention of licensee management. The class was subsequently retrained and tested to ensure that training objectives were met.

b.2.3 System Walkdown

Complete system walkdowns, covering the entire scope of the system, were required under the SHRR procedure. These were conducted using EN-DP-01503, System Walkdowns. The walkdowns were led by the SHRR team leader, generally conducted by the entire team, and deficiencies were identified on CRs. To assess the quality of SHRR walkdowns, the inspectors conducted a plant-wide walkdown which included SHRR and LIR systems. The intent was to compare inspector-identified deficiencies to those of the walkdown team. The inspectors' assessment of the quality of the walkdown was based, in part, on the number and significance of discrepancies found by the inspectors, but not by the teams. After the inspectors' walkdown was completed, the inspectors reviewed a sample of the CRs issued to assess the number and significance of discrepancies identified by the walkdown teams.

c.2.3 Observations and Findings

No findings were identified. The inspectors identified a very small number of minor discrepancies not identified by the SHRR walkdown teams; the licensee issued CRs to document the inspectors' observations.

Among the discrepancies was inconsistency in the lubrication of manually-operated valves. The inspectors noted that for three identical manual valve operators, one appeared to be over-greased, one appeared to be satisfactory, and one valve operator did not have a grease fitting installed. This became an emergent issue which is discussed in Section b.2.6 below. Another discrepancy was inconsistency in greasing of seismic support struts. The inspectors noted that one seismic strut near a Component Cooling Water pump was over-greased while the grease fittings on a nearby strut were painted over. This became an emergent issue which is also discussed in Section b.2.6 below.

The inspectors concluded that the system walkdowns conducted by the licensee using EN-DP-01503, System Walkdowns, were thorough and appropriate to the circumstances. This conclusion was based on the following:

- the number of deficiencies identified by the walkdown teams;
- the inspectors did not identify any significant deficiencies missed by the licensee; and
- the number of deficiencies found by the inspectors, but not by the teams, was very small.

b.2.4 Engineering Assessment Board (EAB)

The role of the EAB was defined in DBE-0001, Engineering Assessment Board Role/Policy in Support of the Return to Service Plan. The EAB's mission was to provide senior level oversight and technical review of engineering products and processes. EAB's charter included:

- assist site and engineering management with oversight of Return to Service activities;
- provide technical review of engineering products as requested by engineering management;
- review Return to Service "Building Blocks;"
- ensure implementation of the "FENOC Engineering Principles and Expectations;"
- provide qualitative assessment of products to identify engineering progress; and
- provide feedback to engineering management and staff.

The inspectors reviewed DBE-0001 to understand the role EAB was expected to play, interviewed the leadership and members of the EAB, examined EAB documented reviews and comments on a large number of engineering products, and attended several EAB meetings where SHA engineering products were reviewed.

c.2.4 Observations and Findings

No findings were identified. The inspectors determined that the EAB made significant contributions to the quality of SHA engineering products. The EAB had several specific responsibilities in both the SHRR and LIR programs. For brevity, EAB activities will only be discussed in this section.

EAB responsibilities in the SHA included review and concurrence with:

- scope, including the identified system boundaries, the selected components, and justification for their selection;
- identified testing or review of other information that assessed on a periodic frequency, the system's risk significant maintenance rule functions;
- recommendations for expanding the scope of review when problems are found; and
- final report to ensure the reviews complied with the procedure and were complete, findings were adequately documented, and activities were in place to address issues.

EAB membership was composed of very experienced consulting engineers; a large percentage had in excess of 30 years of nuclear experience. EAB subcommittees were established to oversee System Health, Program Review, and Management and Human Performance. Early in the SHA program, through its review and comments on system scope and boundaries, EAB established a high standard for completeness, accuracy, and depth of detail. EAB members were provided engineering products which were examined in detail. EAB then met with the author and the supervisor who presented the product and responded to EAB questions and comments. In all the meetings that the inspectors attended, EAB members were clearly well-prepared. Questions and comments ranged from process to procedural to technical to philosophical; all were in-depth, focused on the product, and challenging. The inspectors' examination of documented reviews of testing memos and completed reports showed that this level of review and comment was consistent with all products.

b.2.5 Report Review

The inspectors reviewed the licensee's completed "System Health Readiness Review Report for the 125/250 VDC System." The inspectors' review was to verify that the activities performed by the licensee during the SHRR report's preparation, review, and approval were completed in accordance with EN-DP-01504, "System Health Readiness Review," Revision 2.

c.2.5 Observations and Findings

No findings were identified. However, the inspector identified two CRs that were considered potential restart items, a fuse issue that may be generic to all electrical systems, and several minor editorial errors.

The two CRs were CR 01-01232, “Crack in Battery Post Seal Ring,” dated June 22, 2001, and CR 02-00412, “DC Voltage Drop Calculation,” dated February 8, 2002.

- Condition Report 01-01232 identified a broken battery post seal nut on cell 21 of the 2P battery. The system engineer concurred that the CR should be changed to a “recommend for restart” item because the 2P battery must be taken out-of-service to complete the CR’s corrective action. Since the 2P battery was being disassembled during the current outage for corrosion product removal (CR 02-03354), this outage would be the appropriate time to replace the broken battery post seal nut.

- Condition Report 02-00412, stated that DC Calculation C-EE-002.01.010 did not adequately address small loads on the dc system. Based on the CR and SHRR report, the inspectors could not conclude that this issue was not a restart item. The system engineer concurred with the inspectors that the CR and the report did not clearly indicate whether the issue involved an actual addition of loads to the battery or was only concerned with the voltage drop of the circuits supplying the small loads. Further review revealed that the issue involved voltage drops and was properly classified.

The potential generic fuse issue was identified by CR 02-04586, “SHRR: 1992 PCAQR Corrective Action Not Yet Completed - Fuse Size,” dated August 23, 2002, which was identified as a “recommend for restart” item by the system engineer. This CR was written following the 125/250 VDC SHRR walk-down, where several switches were identified with a maintenance information tag (sticker) stating “PCAQR 92-0030.” The PCAQR addressed several circuits throughout the plant where the installed fuse did not match that specified by drawing E-2014. Drawing E-2014 was the licensee’s controlled fuse drawing. All the fuses identified by the 1992 PCAQR were evaluated and determined to be acceptable for continued operation with the understanding that the fuses would be replaced upon fuse failure with the correct fuse. However, the E-2014 drawing was not annotated to identify that upon fuse failure the fuse was to be replaced per the PCAQR. The inspectors were concerned that this issue may be generic to all electrical systems and not just the 125/250 VDC system. The system engineer concurred with the inspectors that the PCAQR identified fuses in other plant systems that should be replaced and that he would ensure that the other affected systems’ system engineer would be made aware of this issue.

Subsequent to the NRC inspectors’ inspection, the 125/250 VDC system engineer issued Milestone #14-1, “System Health Readiness Review for 125/250 VDC System,” Amendment 2, Revision 00, dated November 14, 2002, which resolved the inspectors concerns identified above.

It was the intent of this inspection to review five completed SHRR reports. At the close of this inspection, two reports had been issued. One of those was discussed above. The inspectors will return to examine four additional reports when all 31 have been formally completed; results of that inspection will be documented in a separate inspection report.

b.2.6 Emergent Issues

Issues, not directly related to SHA, but needing licensee attention, were identified throughout the course of the inspection as inspectors walked down systems, reviewed condition reports, interviewed licensee staff, or examined other system health documents. The inspectors monitored the licensee's response to these issues to gain insights on the licensee's ability to understand the issue, determine the extent of condition, assess significance, and identify and implement appropriate corrective actions.

c.2.6 Observations and Findings

During the plant-wide walkdown, the inspectors noted inconsistencies in lubrication of identical manual valve operators. A CR was issued and the licensee staff began to examine the issue. In discussions with the staff, it was revealed that although the need had been recognized, the station had no program for consistent maintenance of critical manual valves. The licensee's staff committed to develop such a program. During a review of Condition Report 02-02397, the inspector noted in the description of the condition, that the station had no preventive maintenance program for molded-case circuit breakers. In discussions with the staff, it was revealed that the need had been recognized, but the program had not been developed or implemented. The licensee staff indicated plans to develop such a program. With these two issues as background, the inspectors questioned the extent of component-based reliability or maintenance programs and learned that the station only had a very small number. Further discussions with the licensee's staff revealed that an October 1999 self-assessment had revealed this condition and recommended the establishment of component-based programs. No action appeared to have been taken. This concern was presented to licensee management, who acknowledged the concern and directed that a CR, documenting the lack of response to the 1999 self-assessment, be issued. Resolution of CR 02-08742 was in progress at the close of the inspection.

During the plant-wide walkdown, the inspectors identified inconsistencies in lubrication of seismic support struts. A CR was issued and the licensee evaluated the condition. The licensee identified that all the seismic supports supplied to the plant during construction used a dry-film lubricant, intended to last for the life of the plant. Greasing was unnecessary but if the strut was greased, it would then need periodic regreasing. The licensee was unable to determine when the strut had been greased or if it had been regreased. A condition report was issued to conduct an extent of condition and to evaluate operability impacts of greasing and then failing to regrease these struts. Resolution of CR 02-06765 was in progress at the close of the inspection.

During review of the licensee's self-assessment conducted on the High Pressure Injection (HPI) system, the inspectors examined a table of late commitments. Commitment 10752, dated November 21, 1979, to submit information on HPI protection against deadheading during a small-break loss-of-coolant accident, was listed as pending. The licensee acknowledged that the commitment tracking system was problematic and in need of corrective action. In response to the inspectors' technical questions on this issue, the licensee staff assembled a closure package which consisted of the November 21, 1979 NRC letter requesting information on the topic, the licensee's December 28, 1979 response, and procedures involving HPI operation. The licensee's December 1979 letter did not properly address the issue of HPI deadheading during small-break loss-of-coolant accident. Two of the procedures were for Integrated Leak Rate Test and contained steps for leaving the HPI recirculation valves open during the test. The current HPI operating procedure, included in the package, contained a caution that during HPI operation taking suction on the containment sump, the recirculation valves must be closed. This is exactly the alignment which could lead to deadheading the HPI pumps during a protracted small-break loss-of-coolant accident. None of the information in the closure package properly addressed the issue. The inspectors expressed their concerns to management regarding this inadequate response. The NRC team inspection, documented in Inspection Report 50-346/2002014, independently raised questions about deadheading the HPI pumps during a small-break loss-of-coolant accident. Consequently, the licensee's analysis, generated as a result of the team inspection, will address the technical issue.

b.3 Latent Issues Reviews

a. Introduction

The inspectors reviewed the plans and procedures for LIRs, monitored reviews in progress, interviewed reviewers, examined scoping and testing memos, walked down systems, reviewed CRs issued that were related to LIRs, and examined emergent issues, i.e., issues not directly related to LIR, but identified as a result of walkdowns or examining LIR documents. LIRs were conducted on the Reactor Coolant, Auxiliary Feedwater, Component Cooling, Emergency Diesel Generator, and Service Water systems.

b. Description

b.3.1 Procedure and Process

LIRs were performed for five systems listed above, all of which were categorized as risk-significant under the licensee's Maintenance Rule program. The intent of LIRs, as stated in the System Health Assurance Plan, was to provide reasonable assurance that five systems could perform their safety and accident mitigation functions. LIRs were conducted using procedures EN-DP-01503, "System Walkdown," and EN-DP-01505, "Latent Issues Review." Revisions to these procedures were issued during the course of reviews; these revisions are listed at the end of this report.

The inspectors reviewed both procedures noted above. EN-DP-01503, "System Walkdown," provided a structured process for conducting system walkdowns and recording deficiencies, and provided lists of potential problems and conditions as criteria for identifying deficiencies. EN-DP-01505, "Latent Issues Review," provided training requirements, documents to be reviewed, a structure and process for defining the scope of the reviews, establishing the testing necessary to support safety functions, selecting data sources and conducting data source reviews, criteria and process for expanding the review scope, and preparation, review, and approval of the final report. These are identical to the SHRR; however, the LIR went into greater detail, included a greater span of data sources, and contained design basis inspection attributes that the SHRR did not. The LIR was also more tightly structured to ensure consistency of review across the five systems.

c.3.1 Observations and Findings

No findings were identified. The inspectors determined that both procedures were well-written, logical, complete, and appropriate to the circumstances. The LIR procedure had the same minor procedural problem as the SHRR procedure, in that there was no formal mechanism in the LIR procedure to ensure that changes mandated by EAB to either the scoping or testing memoranda would be reflected back into the walkdowns or document reviews. As with the SHRR procedure, this was addressed in a procedure revision.

b.3.2 Team Leader Meeting

The licensee held a weekly meeting with LIR team leaders to review progress, discuss review approaches, identify common issues, and resolve problems. The inspectors attended one meeting.

c.3.2 Observations and Findings

The meeting was attended by all team leaders, assistant team leaders, system health assurance supervisors, and engineering management. The meeting was well organized and conducted; there was a prepared agenda which was followed. There was a good exchange of information, team leaders and supervisors spoke frankly about progress, problems, and emerging issues.

b.3.3 System Walkdown

The inspectors performed a walkdown of the auxiliary feedwater system and reviewed the results of the licensee's previous walkdown efforts. The purpose of the walkdown was to assess the physical condition of the system and verify the quality and thoroughness of the licensee's previous efforts. The licensee's procedure EN-DP-01503, Revision 2, "System Walkdowns," was reviewed prior to the walkdown.

c.3.3 Observations and Findings

Overall, the licensee's walkdown efforts were found to be effective. The materiel condition of the auxiliary feedwater system appeared to have issues which required corrective actions.

The "System Walkdowns" procedure provided reasonable guidance for identifying any materiel degradations and cleanliness deficiencies in the system. The licensee's walkdown efforts identified numerous issues, especially in the areas of environmental qualification and high energy line break. The inspector identified three conditions adverse to quality which had not been previously identified by the licensee's effort: Fitting leakage and boric acid build up was found on tubing from CW-275J and sample cooler S6B2. The licensee issued condition report CR 02-06268 to document the leakage. Fluid leakage from a hydraulic snubber near orifice AF-4630 was noted. The licensee issued condition report CR 02-06273 to document the leakage. Bearing lube oil supply and return lines were found rubbing together on auxiliary feedpump 1-1. The licensee issued condition report CR 02-06274 to document this condition.

b.3.4 Emergent Issues

As the LIRs progressed, the licensee began to analyze and trend the CRs that were being written. This "collective significance" review was expanded to include self-assessment results, EAB program reviews, SHRR issues, and the NRC team inspection. The collective significance review revealed a number of problem areas common to all five of the LIRs. Among these problem areas were design basis validation, environmental qualification, high energy line break, missing or flawed calculations, calculation control, accident analysis, system descriptions, and configuration management.

The identification of these common problem areas resulted in the recognition by licensee management that the scope of the SHA needed to be expanded. The inspectors reviewed the CRs issued as a result of the collective significance review, examined the list of common problem areas and the underlying data, and met repeatedly with SHA staff to monitor the status of the review and development of expansion plans.

c.3.4 Observations and Findings

No findings were identified. The licensee examined several expansion plan methods for feasibility, effectiveness, efficiency, scope, and depth of review. At the close of this inspection, a final plan had not been adopted. The inspectors will continue to monitor the licensee's progress on this issue.

One of the proposed expansion methods involved use of the Design Basis Document Validation Program (DBDVP), which the licensee had committed to complete in response to the NRC's October 1996 10 CFR 50.54.f letter on adequacy and availability of design bases information. The licensee compared deficiencies identified during the LIR to those identified during the DBDVP. The expectation was that if there was good correlation on findings between the two programs, then the findings of the DBDVP would be used as the basis for expansion. The licensee's examination of the DBDVP concluded that there was insufficient correlation between the two programs to support using DBDVP for expansion plans. In addition, the licensee's review identified problems with the DBDVP; the program had not been completed and a portion of the deficiencies identified had not been properly corrected.

The inspectors reviewed all of the related correspondence, the DBDVP instruction, the Design Basis Validation Report of the Service Water System, and the Service Water System Description. The inspectors also interviewed licensee staff members who had been involved with the project. The project, though a commitment to NRC in response to the 10 CFR 50.54.f letter, was delayed about two years due to engineering resource considerations. The licensee, on recognizing that station resources would remain a restraint, elected to contract for the reports. Two engineering organizations were contracted to prepare the validation reports and work on the project was commenced. From all of the systems validated, there were slightly more than 1000 identified deficiencies. These were characterized as either high, medium, or low significance and work was initiated to correct them. At the close of this inspection, approximately 200 deficiencies had not been corrected. The inspectors reviewed the deficiency tracking list and open item log sheets for the service water and found where the resolution of an issue assigned a high significance rating was inadequate. The issue concerned rated flow in the service water system description that didn't include all possible flows. The prescribed resolution for this deficiency was that it was to be corrected in the system description. It failed to recognize that the analyses related to rated service water flow or using rated service water flow needed to be examined. This deficiency was noted by both the LIR team and the NRC team inspection. As corrective action, the licensee plans to:

- establish an event time line of identified deficiencies and opportunities to improve design information availability and adequacy;
- identify why the DBDVP was not completed;
- confirm that the DBDVP discovery phase was adequate; and
- evaluate why the DBDVP and other, prior programs and activities did not resolve the identified discrepancies.

b.3.5 <u>Report Review</u>

Planning for this inspection included a detailed review of all five LIRs. This was considered an import review effort because these were the most in-depth of all the licensee's reviews and conclusions drawn on the quality of the LIRs would be an important considered in assessing the over quality of the SHA effort .

c.3.5 <u>Observations and Findings</u>

At the close of this inspection, none of the LIR reports had been reviewed or approved by licensee management and were therefore unavailable for inspection. The inspectors will return to examine these reports when they have been formally completed; results of that inspection will be documented in a separate inspection report.

b.4 <u>Quality Assessment Oversight</u>

a. <u>Introduction</u>

During development of the Restart Action Plan and the related seven building blocks, licensee management recognized the necessity of quality assurance oversight throughout the process. Consequently, as the building block plans were being developed, the Nuclear Quality Assessment (NQA) organization prepared a plan for oversight of restart activities. The plan, entitled "Nuclear Quality Assessment Oversight of Davis-Besse Return to Service Plan," Revision 1, was approved by the Vice President of FirstEnergy Oversight on July 22, 2002. The stated mission was to provide oversight and verify the adequacy of activities conducted as part of the Return to Service Plan. For each of the seven building blocks, the NQA plan contained specific objectives to be accomplished through monitoring and assessment of key activities. The inspectors reviewed the NQA oversight plan, met periodically with NQA staff and management, reviewed Quality Field Observations (QFO), reviewed CRs written by NQA staff, and reviewed the three independent system reviews performed by the NQA staff.

b. Description

b.4.1 Planning

To meet the objectives spelled out in the oversight plan, the NQA staff developed a comprehensive program of review and monitoring during the development and implementation of SHA processes. The program included review of training, attendance at ORR, EAB, Restart Safety Review Board, and Restart Senior Management Team meetings, in-line review and comment for SHRR and LIR inspection plan and procedure development, assessment of scope and testing for SHRR and LIR, oversight of walkdowns, independent system health readiness reviews conducted in accordance with the SHRR procedure, and a comparison between the SHRR team and NQA results for the selected system.

c.4.1 Observations and Findings

No findings were identified. The inspectors determined that NQA had developed a comprehensive oversight program to assess the implementation of the SHA plan. During initial discussion with NQA staff and management, the inspectors' recognized that while there was a provision for generation of a quarterly roll-up of QFOs, NQA had not established how the comprehensive results of monitoring and reviews of SHA implementation would be documented for presentation to senior licensee management. After deliberation, NQA management elected to prepare a complete roll-up report of assessment activities, findings and observations, and conclusions after the SHA programs were completed. The inspectors considered this acceptable.

b.4.2 Monitoring

The NQA plan directed frequent monitoring of walkdowns, briefings, LIR and SHRR team meetings, and review boards. These activities were documented through issuance of QFOs, in accordance with NOP-LP-2004, "Internal Assessment Process," and issuance of CRs in accordance with NOP-LP-2001, "Condition Report Process."

c.4.2 Observations and Findings

The inspectors' review of CRs and QFOs confirmed the frequency and depth of NQA involvement in process and procedure development; NQA comments and concerns strengthened the review programs.

b.4.3 Independent System Review

The NQA plan for oversight directed the independent performance of three SHRRs using EN-DP-01504, "System Health Readiness Reviews." These independent reviews were to be conducted by NQA staff and the results compared to the findings of the SHRR teams for the selected systems, which were 125/250VDC Electrical Distribution, Station and Instrument Air, and Decay Heat Removal/Low Pressure Injection. The inspectors reviewed the reports of the three independently performed reviews and the comparative analysis for the 125/250VDC Electrical Distribution system, which was issued as a QFO.

c.4.3 Observations and Findings

No findings were identified. The inspectors found that the independent reviews had been conducted in accordance with the SHRR procedure. The inspectors determined that the findings between the two reviews were essentially similar; this was borne out by the review of the comparative analysis.

b.5 Self-Assessment

a. Introduction

After being informed that the HPI, 4160VAC Electrical Distribution, and Service Water systems had been selected for examination by the NRC design team inspection (Inspection Report 50-346/02-14(DRS)), the licensee elected to perform self-assessments of the three systems. NRC encourages licensees to perform self-assessments as a means of identifying and correcting their own issues.

b. Description

The licensee conducted the self-assessments under the guidance of the FENOC Focused Self-Assessment Guideline, Revision 0, issued December 2001. Each system was reviewed by a separate team led by a member of the licensee's staff, and composed of licensee and consultant engineers. As is typical of these types of self-assessments, the licensee used NRC Inspection Procedure 71111.21, "Safety System Design and Performance Capability," to conduct the system reviews.

c. Findings and Observations

No findings were identified. The inspectors reviewed the Focused Self-Assessment Guideline, the staffing of the three review teams, and the completed reports for all three systems. The reports were thorough and identified some significant issues with each of the three systems.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. L. Myers and other members of licensee management and staff at the conclusion of the inspection on November 13, 2002. The licensee acknowledged the information presented.

KEY POINTS OF CONTACT

DAVIS-BESSE
D. Baker, Life Cycle Management (A) Manager
R. Cooper, Consultant
R. Fast, Plant Manager
J. Grabnar, Design Basis Engineering Manager
E. Grindahl, Quality Assurance
D. Gudger, Learning Organization Manager
D. Haskins, Human Resources Manager
S. Loehlein, Quality Assurance Manager
E. Matranga, Plant Engineering
P. McCloskey, Regulatory Affairs Manager
D. Miller, Compliance Supervisor
G. Mountain, Licensing Engineer
L. Myers, Chief Operating Officer
L. Pearce, Vice President, Oversight
J. Powers, Engineering Director
P. Roberts, Maintenance Manager
M. Roder, Operations Manager
J. Rogers, Plant Engineering Manager
C. Price, Business Manager
R. Schrauder, Services Director
B. Saunders, President, FENOC
L. Thornsberry, Plant Engineering
S. Wise, Operations Superintendent

NUCLEAR REGULATORY COMMISSION
J. Grobe, Chairman, Davis-Besse Oversight Panel
C. Lipa, Chief, Reactor Projects Branch 4
S. Thomas, Senior Resident Inspector

LIST OF ACRONYMS USED

AIT	Augmented Inspection Team
CR	Condition Report
CRDM	Control Rod Drive Mechanism
DBDVP	Design Basis Document Validation Program
EAB	Engineering Assessment Board
HPI	High Pressure Injection
LIR	Latent Issues Review
NQA	Nuclear Quality Assessment
NRC	Nuclear Regulatory Commission
ORR	Operational Readiness Review
PCAQR	Potential Conditions Adverse to Quality Report
PDR	Public Document Room
QA	Quality Assurance
SHA	System Health Assurance
SHRR	System Health Readiness Review
URI	Unresolved Item

LIST OF DOCUMENTS REVIEWED

The following is a list of licensee documents reviewed during the inspection, including documents prepared by others for the licensee. Inclusion on this list does not imply that NRC inspectors reviewed the documents in their entirety, but that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion on this list does not imply NRC acceptance of the document, unless specifically stated in the inspection report.

Procedures

EN-DP-01503	System Walkdown, Revision 02, August 10, 2002
EN-DP-01504	System Health Readiness Review, Revision 00, August 21, 2002
EN-DP-01504	System Health Readiness Review, Revision 02, October 16, 2002
EN-DP-01505	Latent Issues Reviews, Revision 00, September 3, 2002
EN-DP-01505	Latent Issues Reviews, Revision 03, October 8, 2002
EN-DP-01506	Borated Water System Inspections (Outside Containment), September 3, 2002
DBE-0001	Engineering Assessment Board Role/Policy in Support of the Return to Service Plan, Revision 0, June 28, 2002
NG-EN-00324	Boric Acid Corrosion Control, July 20, 2002
NG-VP-00100	Restart Action Plan Process, Revision 01, August 23, 2002
NG-VP-00100	Restart Action Plan Process, Revision 02, August 23, 2002
NOP-ER-2001	Boric Acid Corrosion Control Program, July 20, 2002
NOP-LP-2001	Condition Report Process, Revision 1,

System Health Readiness Review Scoping Memos

Steam Feed Rupture Control System Scope Memo, September 19, 2002
125/250 VDC System Scope Memo, August 26, 2002
High Pressure Injection System Scope Memo, September 16, 2002
Anticipatory Reactor Trip System Scope Memo, September 11, 2002
EDG Ventilation System Scope Memo, September 20, 2002

Condition Reports Generated from Inspection

02-05578	LIR Training Effectiveness
02-06565	SHRR LIR Review of Change Initiating Documents
02-06261	SHRR Boron Identified on CS17 Packing Area
02-06621	SHRR LIR Reviews Initiated before Scoping Approved
02-06723	SHRR LIR NRC Concern regarding Site's Lubrication
02-06765	Sway Strut Bushing Grease Fittings, September 26, 2002
02-07011	SHRR LIR NRC Concerns about System Review Scoping
02-07869	NRC Inspector's Concern Regarding Supervisor Comment for CR, October 11, 2002
02-08432	Containment Design Basis Calculation, October 21, 2002
02-08742	Inadequate Followup to Self Assessment 1999-0076, October 28, 2002
02-09036	Greasing of Struts, November 5, 2002

Condition Reports (CR)

02-02397	IPR: Breaker Reliability Program, May 31, 2002
02-03157	HELB in Turbine Building Effects on AFP Rooms, July 11, 2002
02-03369	Quality Expectations, July 17, 2002
02-03828	SHRR: ARTS Walkdown Findings from 8-7-02 for PSL4535A, B, C, D, August 7, 2002
02-03895	LIR-EDG-Two Instrument Tubing Lines Damaged, August 7, 2002
02-03923	SHRR Walkdown DH Train 1 DW143 Demin Water Valve Leakby, August 9, 2002
02-03925	SHRR Walkdown Decay Heat Train 1 Cooler Room - Scaffold Pole, August 9, 2002 02-02941 Operational Readiness Review Action Items, July 2, 2002
02-04021	SHRR Walkdown Finding During Containment System Walkdown, August 11, 2002
02-04041	SHRR Walkdown Items - RPS CTMT Press SW Sensing Line Guard, August 8, 2002
02-04033	Failure to Process Condition Reports through SRO Review in a Timely Manner, August 12, 2002
02-04047	SHRR Walkdown Items - Outboard Electrical Penetration Cabinet Generic Issues, August 9, 2002
02-04085	LIR-EDG - EDG 1 Air Intake Filter Can Use Paint to Overcoat Rusting, August 11, 2002
02-04198	LIR-EDG 1 - Elec Maintenance Tag on Hand Switch (C3617), August 12, 2002
02-04473	SHRR - I&C Comment Regarding Test Points during Walkdown, August 13, 2002
02-04501	LIR - EDG 2 Cable Pull Wire Left in Place, August 17, 2002
02-04521	LIR - EDG 2 Panel C3616 Test Switch TS-3 Plastic Cover Broken, August 17, 2002
02-04543	SHRR: Battery Room 2 Deficiencies, August 20, 2002
02-04546	SHRR: Interlock for DC Panel Supply Breakers, August 20, 2002
02-04572	LIR-EDG-DO119 Piping Needs to be Cleaned and Painted, August 16, 2002
02-04578	LIR-EDG-EDG1-2 Day Tank Room Needs General Clean & Painting All Equip & Floor, August 16, 2002
02-04581	LIR-EDG-HISNP 1951A Switch Label is Missing, Label “Start/Stop,” August 16, 2002
02-04635	LIR-Emergency Diesel Generator 1-2, August 17, 2002
02-04782	Potential Omission of LCO for Delay Time of Fuel Movement to Spent Fuel Pool, August 22, 2002
02-04812	LIR CCW - Lack of Identification Tags on Instrumentation Valves, August 22, 2002
02-05066	LIR-AFW-ST138, August 23, 2002
02-05092	LIR-AFW-Service Water valve SW6392, August 23, 2002
02-05101	ORR - System Condition Report for Steam Feed Rupture Control System, August 27, 2002
02-05103	ORR - System Condition Report for Condensate System, August 26, 2002
02-05125	ORR - System Condition Report for Non-nuclear Instrumentation, August 19, 2002

02-05132	ORR - System Condition Report for Integrated Control System, August 19, 2002
02-05135	ORR - System Condition Report for RPS, DSS, and NI, August 19, 2002
02-05137	ORR - System Condition Report for Decay Heat Removal/LPI System, August 28, 2002
02-05138	ORR - System Condition Report for Radiation Monitoring System, August 27, 2002
02-05140	ORR - System Condition Report for Switchyard and Transformers, August 24, 2002
02-05141	ORR - System Condition Report for Main Feedwater Pumps/Turbines/Piping System, August 26, 2002
02-05143	ORR - System Condition Report for 125/250 VDC System, August 17, 2002
02-05144	ORR - System Condition Report for Main Steam System, August 26, 2002
02-05146	ORR - System Condition Report for Anticipatory Reactor Trip System, August 15, 2002
02-05147	LIR Design Basis Recovery, August 28, 2002
02-05149	ORR - System Condition Report for Motor Driven Feedwater Pumps, August 26, 2002
02-05150	ORR - System Condition Report for Emergency Diesel Generator, August 21, 2002
02-05157	BWST Level Shift Log Acceptance Criteria May Not Meet TS 3.5.4.A Requirements, August 28, 2002
02-05191	SHRR: 480VAC MCC & MCCB Maintenance Issues, August 28, 2002
02-05408	SHRR: Testing Review - Trip Alarm Excluded from RPS Procedures, September 4, 2002
02-05409	SHRR: Testing Review-Not Verifying Ch Trip Light on Reactor Trip Module, September 4, 2002
02-06040	Issues Identified during SHRR Final Report Presentation, September 14, 2002
02-06259	SHRR LIR System Health Assurance Reviews, September 19, 2002
02-06313	LIR - EDG Exciter/Voltage Regulator PM May Not be Adequate, September 20, 2002
02-06398	Some Safety-Related Breakers Lacking Pms, September 20, 2002
02-06436	SSDPC Collective Significance of Issues from SW Self Assessment and LIR, September 21, 2002
02-06582	LIR-RCS: —273R11 Does Not Reflect the As-Built Plant Configuration, September 24, 2002
02-06770	LIR-AFW-CR 95-0703 Action to Prevent Recurrence Missing, September 26, 2002
02-06819	Inaccurate Input Provided by Contractor for NRC Correspondence, September 26, 2002

<u>Correspondence</u>

Log 4928	Ltr: James M. Taylor to R. J. Farling, Request for Information Pursuant to 10 CFR 50.54(f) Regarding Adequacy and Availability of Design Bases Information, October 9, 1996
Log 4954	Memo: Ledyard B. Marsh, Meeting with NEI and Licensees to Discuss Generic Letter (GL) 96-06, “Assurance of Equipment Operability and Containment Integrity during Design-Basis Accident Conditions,” November 22, 1996

Serial 2438	Ltr: Centerior Energy to USNRC, Response to NRC Request for Information Regarding Adequacy and Availability of Design Bases Information Regarding Adequacy and Availability of Design Bases Information, February 11, 1997
Log 5004	Ltr: Allen G. Hansen to John K. Wood, Response to October 9, 1996 Request for Information Pursuant to 10 CFR 50.54(f) Regarding Adequacy and Availability of Design Bases Information, Davis-Besse Nuclear Power Station, Unit No. 1 (TAC No. 97583), February 25, 1997
Log 5024	Ltr: Allen G. Hansen to John K. Wood, Planned Design Inspection, Davis-Besse Nuclear Power Station, Unit No. 1, March 27, 1997
Serial 2455	Ltr: Centerior Energy to USNRC, Plan And Schedule for Completion of the DBNPS Design Basis Validation Program, March 31, 1997
Log 5173	Ltr: Allen G. Hansen to John K. Wood, Davis-Besse Nuclear Power Station, Unit 1 - Design Inspection - NRC Inspection Report No. 50-346/97-201 (TAC No. M99129), November 19, 1997
Serial 2623	Ltr: Guy G. Campbell to USNRC, Status of the Design Basis Validation Program and the Planned Program to Convert to the Improved Standard Technical Specifications, December 17, 1999

Other Documents

	Davis-Besse Return to Service Plan, Revision 2, August 6, 2002
	Nuclear Quality Assessment Oversight of Davis-Besse Return to Service, Revision 1, July 22, 2002
RSMT	Davis-Besse Restart Senior Management Team Charter, Revision 00, June 24, 2002
	Davis-Besse Restart Overview Panel Charter, Revision 0, June 7, 20002
RSRB	Davis-Besse Restart Station Review Board Charter, Revision 00, June 24, 2002
	Davis-Besse System Health Assurance Plan, Revision 2, August 5, 2002
	Davis-Besse System Health Assurance Plan, Revision 3, September 9, 2002
	System Health Assurance Discovery Action Plan, Revision 0, August 5, 2002
	System Health Assurance Discovery Action Plan, Revision 2, October 15, 2002
	FENOC Engineering Principles and Expectation, July 10, 2002
NED 87-10338	Memo, Sway Strut Bushing Grease Fittings, July 29, 1987
	Manual Valve Component Reliability Template Basis Document
ENDP-01506	Leakage Reduction Program Manual, Revision 00, July 18, 2001
	Design Basis Document Validation Program, Revision 1, August 21, 1997
SD-018	System Description for Service Water System, Revision 2, August 4, 1995
	Design Basis Document Validation Report of the Service Water (SW) for Davis-Besse Power Plant by Sargent & Lundy, LLC, December 23, 2000
	Training Lesson Plan - Borated Water System Inspections (Outside Containment), September 5, 2002
TM-108	Job Familiarization Guidelines - Mechanical Boric Acid Corrosion Control Inspector (Applicable to EN-DP-01501 Only), July 22, 2002
	Focused Self-Assessment Guideline, Revision 0, December 2001
SA 2002-0093	Davis-Besse NPS Self-Assessment Service Water System Report, October 22, 2002

SA 2002-0094	Davis-Besse NPS Self-Assessment High Pressure Injection System Report, October 22, 2002
SA 2002-0095	Davis-Besse NPS Self-Assessment 4160 VAC System Report, October 22, 2002
	Quality Assurance Review of System Health Readiness Review for Decay Heat Removal/Low Pressure Injection System, September 27, 2002
	Quality Assurance Review of System Health Readiness Review for 125/250 VDC System, Revision 0, October 5, 2002
	Quality Assurance Review of System Health Readiness Review for Station and Instrument Air System, Revision 0, November 6, 2002
	Davis-Besse Operation Readiness Report, Revision 0, October 29, 2002
NPE-99-0076	Plant Equipment Reliability Self-Assessment, October 22, 1999

ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-346
License No:	NPF-3
Report No:	50-346/02-14(DRS)
Licensee:	FirstEnergy Nuclear Operating Company
Facility:	Davis-Besse Nuclear Power Station
Location:	5501 North State Route 2 Oak Harbor, OH 43449
Dates:	September 23 through November 13, 2002
Inspectors:	B. Bartlett, Lead Inspector J. Ellegood, Resident Inspector R. Daley, Reactor Inspector R. Deese, Resident Inspector D. Prevatte, Mechanical Consultant M. Shlyamberg, Mechanical Consultant
Approved by:	Ronald N. Gardner, Chief Electrical Engineering Branch Division of Reactor Safety

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SUMMARY OF FINDINGS

IR 05000346-02-14; FirstEnergy Nuclear Operating Company; on 09/23-11/13/2002; Davis-Besse Nuclear Power Station. Safety System Design and Performance Capability.

This was a special inspection of the design and performance capability of the service water system, high pressure injection system, and the safety-related portions of the 4,160 volt AC system. It was conducted by regional engineering specialists, resident inspectors and two consultants. The inspection identified four NCVs, three of which had multiple examples, and two unresolved items. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609 “Significance Determination Process” (SDP). Findings for which the SDP does not apply are indicated by “No Color” or be assigned a severity level after USNRC management review. The USNRC’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. Inspector Identified Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a Non-Cited Violation (NCV) of Technical Specification surveillance requirement 4.2.5.H, associated with failure to re-verify High Pressure Injection pump flow following modifications that could alter system flow characteristics.

  This finding was determined to be more than minor because it affected the mitigation systems cornerstone objective. This finding screened as Green in the SDP phase 1, since this issue was not an actual loss of a safety function. Because the finding was of very low safety significance, and was captured in the licensee’s corrective action system this finding is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (Section 1R21.3).

- Green. The inspectors identified an example of a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, associated with a non-conservative TS value for the 90 percent degraded voltage relay.

  This finding screened as Green in the SDP phase 1, since this issue was a design deficiency that was confirmed not to result in loss of function in accordance with Generic Letter 91-18 (Revision 1). Because the finding was of very low safety significance, and was captured in the licensee’s corrective action system this finding is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (Section 1R21.5).

  Green. The inspectors identified an example of a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, associated with non-conservative relay setpoint calculation for the 59 percent undervoltage relay.

This finding screened as Green in the SDP phase 1, since this issue does not contribute to the likelihood of a Primary or Secondary system Loss of Coolant Accident (LOCA) initiator, does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available, and does not increase the likelihood of a fire or internal/external flood. Because the finding was of very low safety significance, and was captured in the licensee's corrective action system, this finding is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (Section 1R21.5).

Green. The inspectors identified an example of a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, associated with an inadequate analytical basis for the setpoint to swap service water system discharge path.

The inspectors considered this finding was more than minor because it could affect the mitigating systems cornerstone objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences attributable to design control. Using the significance determination process, the safety significance was determined to be very low (Green) because the finding did not screen as potentially risk significant due to a seismic, fire, flooding, or severe weather event. Because the finding was of very low safety significance, and was captured in the licensee's corrective action system, this finding is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (Section 1R21.5).

- Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI, associated with a service water surveillance test that did not use worst case values.

  This finding screened as Green in the SDP phase 1, since this issue was a testing deficiency that was confirmed not to result in loss of function in accordance with GL 91-18 (Revision 1). Because the finding was of very low safety significance, and was captured in the licensee's corrective action system this finding is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (Section 1R21.6).

- Green. The inspectors identified a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion XVI, associated with inadequate corrective actions for service water pump discharge check valves test acceptance criteria.

  This finding screened as Green in the SDP phase 1, since the finding did not screen as risk significant due to a seismic, fire, flooding, or severe weather event. Because the finding was of very low safety significance, and was captured in the licensee's corrective action system this finding is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (Section 1R21.6).

Cornerstone: Barrier Integrity

- Green. The inspectors identified an example of a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, associated with the lack of a design basis analysis for containment isolation valve backup air supply accumulators.

  This finding screened as Green in the SDP phase 1, since this issue did not represent an actual open pathway in the physical integrity of reactor containment. Because the finding was of very low safety significance, and was captured in the licensee's corrective action system this finding is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (Section 1R21.1).

- Green. The inspectors identified an example of a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, associated with inadequate blowdown provisions for Containment Air Cooler (CAC) backup air accumulators.

  This finding screened as Green in the SDP phase 1, since this issue did not represent an actual open pathway affecting the physical integrity of reactor containment. Because the finding was of very low safety significance, and was captured in the licensee's corrective action system, this finding is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (Section 1R21.1).

REPORT DETAILS

Background and Event Overview

On March 6, 2002, Davis-Besse personnel notified the NRC of degradation (corrosion) of the reactor vessel head material adjacent to a control rod drive mechanism (CRDM) nozzle. This condition was caused by coolant leakage and boric acid corrosion of the head material induced by an undetected crack in the adjacent CRDM nozzle. The degraded area covered in excess of 20 square inches where the low-alloy structural steel was corroded away, leaving the thin stainless steel cladding layer. This condition represented a loss of the reactor vessel's pressure retaining design function, since the cladding was not considered as pressure boundary material in the structural design of the reactor pressure vessel. While the cladding did provide a pressure retaining capability during reactor operations, the identified degradation represented an unacceptable reduction in the margin of safety of one of the three principal fission product barriers at the Davis-Besse Nuclear Power Station (reference NRC report 50-346/02-03(DRS)).

As part of the licensee's Return to Service plan and as corrective action for the circumstances that led to the vessel head degradation, the licensee implemented the "Davis-Besse System Health Assurance Plan" (DBSHAP). This plan described activities to review plant systems prior to restart to ensure that plant systems were in a condition that would support safe and reliable operation. To assess the quality of the licensee's reviews, the NRC conducted an in-depth design and performance capability inspection of three of the systems reviewed by the licensee. Given the high public interest in this subject area at Davis-Besse, and therefore the need to clearly communicate the rationale for NRC staff conclusions regarding the effectiveness of licensee extent of condition inspections, this report documents the inspectors' observations.

1. REACTOR SAFETY

Cornerstones: Mitigating Systems and Barrier Integrity

1R21 Safety System Design and Performance Capability (71111.21)

Introduction

Inspection of safety system design and performance verifies the initial design of the Davis-Besse plant as well as subsequent modifications of the plant, and provides monitoring of the capability of the selected systems to perform design bases functions. As plants age, the design bases may be lost and important design features may be altered or disabled. The plant risk assessment model is based on the capability of the as-built safety system to perform the intended safety functions successfully. This inspectable area will verify aspects of the mitigating systems and barrier integrity cornerstones for which there are no indicators to measure performance.

The objective of the safety system design and performance capability inspection was to assess the adequacy of calculations, analyses, other engineering documents, and operational and testing practices that were used to support the performance of the service water, high pressure injection, and the safety-related portions of the 4,160 volt

AC systems during normal, abnormal, and accident conditions. The inspection was performed by a team of inspectors that consisted of a team leader, two Region III inspectors, one Region IV inspector, and two consultants.

The service water, high pressure injection, and 4,160 volt AC systems were selected for review during this inspection. This selection was based upon:

- having a high probabilistic risk analysis ranking;
- selecting one system from the licensee's list of 5 systems receiving a Latent Issues Review;
- selecting two systems from the licensee's list of 31 systems receiving System Health Readiness Reviews and;
- not having received recent NRC review.

The criteria used to determine the system's performance included:

- applicable Technical Specifications;
- applicable Updated Final Safety Analysis Report sections; and
- the systems' design documents.

.1 System Requirements

a. Inspection Scope

The team reviewed the following attributes for the service water (SW) system, high pressure injection (HPI) system, and the safety-related portions of the 4,160 Vac system: (1) process medium (water, steam, and air); (2) energy sources; (3) control systems; and (4) equipment protection. The team verified that procedural instructions to operators were consistent with the operator actions required to meet, prevent, and/or mitigate design basis accidents. The team's review considered requirements and commitments identified in the Updated Final Safety Analysis Report (UFSAR), Technical Specifications (TS), design basis documents, and plant drawings. This review further verified that the required support functions for the selected systems would be available.

The team verified that the system needs for the selected systems were met. The supply of air, water, steam, and electrical power required by the TS were verified through a review of the design of the selected systems, and those systems providing support functions.

The team verified equipment for the selected systems required to operate and/or change state during accidents and events would have control power available. The team further reviewed the adequacy of alarm setpoints and verified that necessary instrumentation and alarms were available to operators for making necessary decisions in coping with postulated accident conditions. In addition, the team verified that the systems' standby alignments were consistent with assumptions in the operating procedures as well as design and licensing basis assumptions.

b. <u>Observations and Findings</u>

Lack of a Design Basis Analysis for Containment Isolation Valve Backup Air Supply Accumulators

The inspectors identified a Green finding that is an example of a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control, associated with a failure to assure that applicable regulatory requirements and the design basis for structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions. Service water (SW) system valves SW-1356, SW-1357, and SW-1358 are the containment air cooler (CAC) outlet containment isolation valves. They are air-operated valves that fail open on a loss of instrument air. Since the plant's instrument air system was nonsafety-related, the containment isolation valves were provided with a safety-related backup air system with accumulators to assure that they could be isolated and held closed for containment isolation under accident conditions. However, no viable design basis description or analyses could be found for the backup air system or for the size of the accumulators. Additionally, no acceptance criteria, basis, or analysis could be found to support the surveillance test which leak-tested this system. Therefore, the ability of the safety-related backup air supplies to perform their safety-related functions of enabling the closure of these valves upon demand for containment isolation could not be verified.

The procedure's acceptance criterion was that the accumulators are capable of stroking the valves and holding them shut for 30 minutes. Discussions with licensee engineers determined that the 30-minute criterion was based on the expectation that instrument air would be restored in this time and that the operators could manually shut the valves if necessary. However, for design basis analysis credit should not be given for restoration of the non-safety instrument air system. In addition, the ability of the plant operators to manually close the air-operated containment isolation valves in an area that could have very high post-accident radiation levels had not been demonstrated.

The licensee informed the inspectors that the lack of a design basis had been identified prior the inspectors' arrival on site. However, condition report (CR) 02-06546 only identified that the basis for the 30-minute test acceptance time could not be located, and this was deemed as only an "administrative inadequacy."

The licensee missed at least two opportunities to have identified and corrected these concerns. The first was when Generic Letter (GL) 88-14, "Instrument Air Supply Problems Affecting Safety-Related Equipment," dated August 8, 1988, was issued to all licensees. The licensee's docketed response letter stated, in part, "Additionally, safety-related accumulators were verified to be sized correctly and to perform as required during a loss of instrument air and other design-basis events."

The second missed opportunity was when these service water valves and operators were replaced with components of completely different design (Modification 99-0039-00, "CAC Temperature Control Valve Replacement," dated June 29, 1999). The modification effort should have prompted a review of the backup air system design bases and capabilities to verify that they were adequate for the new equipment.

10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires that “Measures shall be established to assure that applicable regulatory requirements and the design basis...are correctly translated into specifications, drawings, procedures, and instructions.” Contrary to this requirement, the licensee failed to correctly translate the design basis requirements for sizing of the safety-related backup air supplies for service water containment isolation valves SW-1356, SW-1357, and SW-1358 into the design.

This finding was determined to be more than minor because it affected the barrier integrity cornerstone objective. This finding screened as Green in the Significance Determination Process (SDP) phase 1 because the issue did not represent an actual open pathway in the physical integrity of reactor containment. Because the finding was of very low safety significance, and was captured in the licensee’s corrective action system as CR 02-07750, this finding is being treated as an example of a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 50-346/2002-014-01a).

<u>Inadequate Blowdown Provisions for Containment Air Cooler Backup Air Accumulators</u>

The inspectors identified a Green finding that is being treated as an additional example of a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” associated with a failure to assure that applicable regulatory requirements and the design basis for structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions. The inspectors determined that the CAC containment isolation valve backup air accumulators were not equipped with blowdown valves or other provisions to allow removal of condensation as described in Updated Safety Analysis Report (USAR) Section 9.3.1.5, which stated, “Regular maintenance of the equipment is performed to ensure cleanliness. This includes regular blowing down of receivers....”

The failure to include blowdown provisions meant that any moisture intrusion into the accumulator would not be identifiable and would not be removable. This would result in the reduction in the amount of air available to maintain the containment isolation valves closed and would result in rust and other debris in the accumulator.

10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires that “Measures shall be established to assure that applicable regulatory requirements and the design basis...are correctly translated into specifications, drawings, procedures, and instructions.” Contrary to this requirement, the licensee failed to include blowdown valves or other provisions to allow removal of condensation as described in Updated Safety Analysis Report (USAR) Section 9.3.1.5.

This finding was determined to be more than minor because it affected the barrier integrity cornerstone objective. This finding screened as Green in the SDP phase 1 since this issue did not represent an actual open pathway in the physical integrity of reactor containment. Because the finding was of very low safety significance, and was captured in the licensee’s corrective action system as CR 02-07750, this finding is being treated as an additional example of a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 50-346/2002-014-01b).

.2 System Condition and Capability

a. Inspection Scope

The team reviewed the periodic testing procedures for the selected systems to verify that the design requirements were adequately demonstrated. The team reviewed the environmental qualification of a sample of system components to verify the capability to operate under design environmental conditions and the assumed operating parameters including: voltage, speed, power, flow, temperature, and pressure. The team also reviewed recent instrument setpoint changes to verify that the design basis or capability for the selected systems had not been affected by the setpoint change process.

The team reviewed the systems' operations by conducting system walkdowns; reviewing normal, abnormal, and emergency operating procedures; and reviewing the Updated Final Safety Analysis Report, technical specifications, design calculations, drawings, and procedures. In addition, the team reviewed the list of active and closed standing orders and operator work-arounds to ensure no design assumptions were invalidated by past or current operator daily practices.

b. Observations and Findings

Failure to Perform Comprehensive Moderate Energy Line Break (MELB) Analysis

Pump Seal Leakage

The inspectors identified an unresolved item associated with a failure to evaluate the environmental effects of a postulated Decay Heat Removal (DHR) pump seal failure. Following a review of the USAR description of a postulated DHR pump seal failure following a postulated Loss of Coolant Accident (LOCA) (Section 3.6.2.7.1.11), and discussions with the licensee, the inspectors determined that only the effects of flooding had been evaluated. The environmental effects of the assumed 120 gallons per minute (gpm) seal failure on the equipment in the area, such as pressurization, increase of humidity and temperature, jet impingement, etc, had not been evaluated.

Due to the interconnection of rooms in the Auxiliary Building, the environmental effects could impact the other emergency core cooling system (ECCS) pump room and the remaining ECCS train. The licensee issued CR 02-07757 to document the inspectors' finding.

The inspectors were unable to fully evaluate the effects of the assumed seal failure on licensee equipment in order to assess whether the finding represented a design or qualification deficiency that would result in a loss of function. At the close of the inspection, the licensee was re-evaluating the effects of a postulated DHR pump seal failure on the operation of plant equipment. This issue will remain as unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01c).

Cracks in Other Moderate Energy Lines

The team's review of USAR Section 3.6.2.7, "Protection Against Environmental Effects Outside the Containment Vessel," and discussions with the licensee identified that critical cracks at selected locations during normal plant shutdown cooling mode for the low pressure injection/decay heat removal (DHR) system had not been evaluated. The effects of those cracks on safety related Structures, Systems, or Components (SSCs) (e.g., pressurization, increase of humidity and temperature, jet impingement) had not been evaluated. Due to the interconnection of rooms in the Auxiliary Building, this environment could potentially reach the other ECCS Pump Room and affect the remaining DHR train. The licensee issued CR 02-07777 to document this team's finding.

Lifting of Service Water Relief Valves SW-3962 and SW-3963

The inspectors identified an unresolved item in that the service water supply header relief valves, SW-3962 and SW-3963, had a history of lifting and not reseating after expected plant transients. The resultant diversion of flow away from the system's safety-related heat exchangers could have, under some conditions, prevented one or both trains of the SW system from performing its safety function.

The service water system was protected against overpressure from the pumps by 6"x 8" relief valves, SW-3962 and SW-3963, on each of the respective supply headers. Since initial plant startup in 1977, a chronic problem existed with these valves lifting during normal system transients that produced pressure pulses in the supply headers. These included pump swaps, system lineup changes, load changes, and high system pressures during winter months when system flows were restricted. Additionally, due to the steady-state operating header pressure often being close to the valves' reseat pressure, they have frequently experienced chatter, resultant damage, and failure to fully reseat. In this condition, the valves could divert substantial flow from the system's heat exchangers that is not accounted for in the system analyses or flow balance tests. Therefore, for this condition, the ability of the system to provide the required design basis flows to the safety-related heat exchangers in both divisions could not be verified. This design also did not meet the requirements of American Society of Mechanical Engineering (ASME) Code, Section III, 1971, Article NB-7400, Paragraph NB-7614.1, "Anti-Chattering and Life Requirements," which stated, "Safety valves shall be designed and constructed to operate without chattering..."

This has been a significant concern for the licensee as evidenced in CRs 00-2478 and 01-0350. One of the licensee's responses has been to structure the system operating procedure, DB-OP-06261, "Service Water System Operating Procedure," with steps to intentionally lower header pressure, such as by opening the strainer blowdown valves, before performing any activities likely to cause the valves to lift. Although this allowed the system to be operated with lowered potential for valve actuations, it did not eliminate the problem, even for normal operations. More important, it did not address the system's safety function and accident-induced pressure transients, such as the automatic isolation of the non-safety portion of the system by the closing of either valve SW-1395 or SW-1399, depending on which division was supporting the turbine building loads at the time, which would produce a relatively large pressure transient. A single failure on the opposite division would render the system unable to perform its safety function. Other events alone, such as loss-of-offsite-power (LOOP) without an accident could cause such a transient with pump restart after starting of the diesel generators. Based on actual plant experience, these appeared to be high probability transient responses.

Therefore, as a result of the system's supply header overpressure protection design, there was a high potential that the SW system could not adequately perform its safety function for design basis accidents and other design basis events. Although the licensee formally identified this concern with respect to operations impact, the safety implications were never formally recognized and documented.

The inspectors determined that the design of the SW system relief valves which could result in a loss of flow to safety-related components was a performance deficiency warranting a significance evaluation. At the close of the inspection, the licensee was re-evaluating the effects of leaking SW relief valves on the operation of plant equipment. The licensee entered the issue into its corrective action program as CR 02-07879. The licensee screened the CR as requiring resolution prior to the mode in which SW was required by plant TS (Mode 4). This item will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01d).

Inadequate Service Water Pump Room Temperature Analyses

The inspectors identified an unresolved item associated with assurance that applicable regulatory requirements and the design basis for structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions. The inspectors questioned whether the licensee correctly translated the USAR commitments regarding the service water pump room temperature limits into analyses that demonstrated these limits would not be violated for design basis conditions.

USAR Section 9.4.5.1, "Service Water Pump Room Ventilation System Design Bases," stated, "The system is designed to maintain the service water pump room and diesel-driven fire pump room between 40°F and 104°F year-round for all modes of operation including post-accident." Calculation 67.005, "Service Water Pump Room Ventilation System Capacity," analyzed the heat loads in the service water pump room and the ability of the ventilation system to maintain the pump room temperatures within this range. The inspectors determined that calculation 67.005 contained multiple non-conservative attributes:

For summer, with an assumed 95°F outside design temperature:

- The calculation did not fully consider accidents *without* a LOOP, in which case, all of the non-1E-powered loads in the rooms, such as the two cooling tower makeup (CTMU) pumps, could remain energized, adding to the heat load.

- The calculation did not consider a seismic event that could start the diesel fire pump as a result of fire system water losses, thereby adding this large heat load.

For winter, with an assumed -10°F outside design temperature:

- The calculation modeled the room temperature as uniform. However, for worst case conditions, the only significant heat source could be one operating service water motor at one end of the room, with vulnerable components at the opposite end. There is approximately 44 feet of separation and an intervening wall with an opening in the approximate center, and there would be no ventilation fans operating.

- The calculation evaluated only heat transfer by conduction through the walls, roof, and floor; it did not account for the fixed open ventilation roof inlets. Heated air from the operating pump would rise and exit the room at the nearer opening and be replaced by -10°F outside air entering the room at the farther opening.

At the close of the inspection, the licensee was re-evaluating the issue of correctly translating the USAR commitments regarding the service water pump room temperature limits into analyses that demonstrated these limits would not be violated for design basis conditions. The licensee entered the issue into its corrective action program as CR 02-07188. The licensee screened the CR as requiring resolution prior to the mode in which SW was required by plant TS (Mode 4). This item will remain as unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01e).

Service Water Pump Room Steam Line Break

The inspectors identified an unresolved item associated with assurance that applicable regulatory requirements and the design basis for structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions. The inspectors questioned whether the licensee correctly translated the USAR commitments regarding the service water pump room environmental limits into analyses that demonstrated these limits would not be violated for design basis conditions.

The inspectors reviewed Calculation C-NSA-085.00-002, "Auxiliary Steam Blowdown in the Intake Structure," that addressed a postulated auxiliary steam line break in the service water pump room. The inspectors determined that the calculation failed to account for any steam condensation in safety-related electrical equipment in the room. Such condensation could render this equipment or equipment powered by or through these components inoperable. Such equipment could include the service water pump motors, the safety-related motor control centers, and pull/junction boxes in the room. USAR Section 3.11.1.2, "Environmental Conditions," stated, "Environmental conditions have been developed for all safety-related areas of the plant...The environmental conditions include temperature, pressure, relative humidity..."

This concern was also identified by the licensee in the Latent Issues Review and documented in CR 02-05966; however, this CR only addressed pull/junction boxes. In order to resolve the issue, the licensee will need to assess the impact of steam condensation on the operation of the SW system.

At the close of the inspection, the licensee was re-evaluating the impact of steam condensation following a postulated heating steam line break. The licensee entered the issue into its corrective action program as CR 02-07475. The licensee screened the CR as requiring resolution prior to the mode in which SW was required by plant TS (Mode 4). This item will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01f).

Cable Ampacity

The inspectors identified an unresolved item associated with assurance that applicable regulatory requirements and the design basis for structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions. The inspectors determined the licensee failed to correctly translate the USAR commitments regarding the cable ampacity analysis for electrical cable passing through ECCS pump room number 115.

ECCS pump room number 115 had an analysis for cable de-rating /ampacity for temperatures up to 120°F, however; the peak calculated temperature in the room is now 124.2°F and the licensee has not performed a derate for the extra 4.2 degrees.

At the close of the inspection, the licensee was re-evaluating the impact of steam condensation following a postulated heating steam line break. The licensee entered the issue into its corrective action program as CR 02-06893. The licensee screened the CR as requiring resolution prior to the mode in which this equipment was required by plant TS (Mode 4). In order to resolve the item, the Licensee will need to assess the impact of the revised temperature analysis on cable ampacity and its effect on safety-related cables passing through room 115. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01g).

.3 Identification and Resolution of Issues

a. Inspection Scope

The team reviewed a sample of problems identified by the licensee in the corrective action program to evaluate the effectiveness of corrective actions related to design issues. The sample included open and closed condition reports going back three years that identified issues related to or affecting the systems and safety-related setpoint issues. The specific corrective action documents that were sampled and reviewed by the team are listed in the attachment to this report. Inspection Procedure 71152, "Identification and Resolution of Problems," was used as guidance to perform this part of the inspection.

The issues addressed by the condition reports reviewed included:

- The disposition of technical specification interpretations to address system and component operability;
- The identification and correction of configuration control events and errors;
- The identification and correction of issues related to testing failures;

- The identification and corrective action associated with personnel errors, primarily in the operations area;
- The identification and correction of safety-related setpoint issues; and
- The identification and correction of apparently degraded equipment.

b. Observations and Findings

Containment Air Coolers Nozzle Loading

On September 5, 2002, the licensee identified a non-conservatism in their analysis of CAC mechanical stresses. This analysis evaluated the connection of the service water system to the CACs. During a LOCA, the service water piping will expand as the water temperature increases. The amount of stress applied to the CAC nozzle is partially determined by the flexibility of the nozzle. In the analysis, the licensee overestimated nozzle flexibility by a factor of one thousand. As a result, the calculated stresses on the nozzle were significantly lower than would actually be experienced during a postulated LOCA or other transient. By reducing nozzle flexibility to more realistic values, the licensee determined that the coolers could exceed code allowable values under either a LOCA or water hammer event. In the case of a LOCA, this would be a common mode failure that could render all three trains of containment air coolers inoperable. The licensee had at least one prior opportunity to identify this error. In 1997, the licensee performed a water hammer analysis to respond to Generic Letter 96-06. This analysis included use of the CAC stress calculations as a base model for the analysis. During development of this analysis, the licensee failed to identify the erroneous nozzle flexibility assumption.

As of the close of this inspection, the licensee had yet to complete the re-analysis using the proper nozzle flexibility. The licensee entered the issue into its corrective action program as CR 02-05563. The licensee screened the CR as requiring resolution prior to the mode in which SW was required by plant TS (Mode 4). This item will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-03e).

SW Pump Curve Allowable Degradation

The inspectors identified an unresolved item associated prompt corrective action to resolve an identified condition where the allowable degradation of the SW pumps did not match the design basis required flow rate from the SW pumps.

In the Latent Issues Review (LIR), the licensee re-identified a condition where the total head across the SW pumps could degrade by as much as 7 percent before corrective action was required under ASME Section XI. The flow balance procedures (DB-SP-3000 and DB-SP-3001) did not adjust the available SW pump head for the maximum possible SW pump degradation.

This issue was documented in CR 02-05369. The team's review of this CR identified that this CR was approved, yet it did not identify a need to evaluate possible generic implications. When questioned about the extent of condition and applicability to other systems, e.g., component cooling system, the licensee agreed that the extent of condition should have been considered and issued CR 02-06863 to document a lack of the extent of condition evaluation. The CR was noted as "...needs to be considered for restart."

At the close of the inspection, the licensee had yet to determine if the SW pumps were performing at a level that would supply the needs of the SW system during all required accident conditions. The licensee entered the issue into its corrective action program as CR 02-07468. The licensee screened the CR as requiring resolution prior to the mode in which SW was required by plant TS (Mode 4). This item will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-03a).

<u>Technical Specification Surveillance Requirement for High Pressure Injection (HPI) Following Modifications</u>

The inspectors identified one Green finding that is being treated as a Non-Cited Violation of TS 4.5.2.H which requires re-verification of HPI pump flow following modifications that could alter system flow characteristics.

The inspectors' review of the HPI pump surveillances, design basis calculation, and the TS requirements determined that TS 4.5.2 H had not been implemented. The TS required verification that the HPI pump is capable of delivering a total of 750 gpm at 400 pounds per square inch gage (psig) at the Reactor Coolant System (RCS) nozzle "...following completions of modifications to the HPI ... subsystems that alter the subsystem flow characteristics..." Calculations and surveillance test procedures address flow rates of about 400 gpm (HPI pump flow test region). Thus, there were no tests or calculations to demonstrate that the HPI pumps complied with TS requirements. The inspectors questioned the licensee about this discrepancy. The licensee stated that the HPI self-assessment conducted in parallel with the team's inspection also identified this issue and was documented in CR 02-06996. The basis for closure of this CR stated:

> "The bottom line of all this is that T.S. 4.5.2 H and the calculations that support it are not well aligned. However, it appears that past testing and acceptance criteria was sufficient to support that the implied requirement is met. This issue should be cleaned up prior to restart to absolutely assure alignment and that testing is in full compliance with requirements."

This CR failed to address that the HPI system was modified such that system flow characteristics were altered. CR 02-06996 was the second CR issued by the licensee to address this failure to comply with the TS requirements. The first CR which identified the failure to comply with the TS requirements was CR 02-03331; however; this CR was being tracked as an administrative issue. When questioned by the team if the required TS 4.5.2 H verification was performed, the licensee was not able to verify the TS required verification was done. Based on this question, the licensee issued CR 02-07468.

The inspectors determined that flow testing was performed following replacement of the HPI impellers and that this flow testing confirmed that the new impellers performed similarly to the old impellers.

This finding was determined to be more than minor because it affected the mitigation systems cornerstone objective. This finding screened as Green in the SDP phase 1, since this issue was not an actual loss of a safety function. Because the finding was of very low safety significance, and was captured in the licensee's corrective action system as CR 02-07468, this finding is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 50-346/2002-014-04).

SW Relief Valves

The inspectors identified an unresolved item associated with safety-related service water relief valves which failed and malfunctioned due to poor design, potentially preventing the system from performing its safety function, and the licensee had not corrected this condition.

At the close of the inspection, the licensee was re-evaluating the effects of leaking SW relief valves on the operation of plant equipment. The licensee entered the issue into its corrective action program as CR 02-07995 and screened the CR as requiring resolution prior to the mode in which SW was required by plant TS (Mode 4). To resolve this issue the Licensee will need to assess the ability of the licensee's SW system to withstand a loss of SW flow due to the partially open relief valves. This issue will remain as unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-03b).

Non-Conservative Difference in Ultimate Heat Sink Temperature Measurements

The inspectors identified an unresolved item associated with plant staff awareness of the non-conservative mismatch between the Ultimate Heat Sink (UHS) temperature, as indicated by the difference between the TS temperature instrument readings, and the 2°F higher actual service water heat exchanger inlet temperatures, and the failure to promptly correct this condition.

The licensee entered the issue into its corrective action program as CRs 02-05372, 02-06177, 02-06332, 02-06336, 02-06370, 02-07004, and 02-07716 and screened the CRs as requiring resolution prior to the mode in which the SW system was required by plant TS (Mode 4). In order to resolve this issue, the licensee and the NRC will need to assess the service water system thermal requirements. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-03c).

.4 System Walkdowns

a. Inspection Scope

The team performed walkdowns of the accessible portions of the selected systems, as well as the required support systems. The walkdowns focused on the installation and configuration of power supplies, piping, components, and instruments. During the walkdowns, the team assessed:

- The placement of protective barriers and systems;

- The susceptibility to flooding, fire, or environmental conditions;
- The physical separation of trains and the provisions for seismic concerns;
- Accessibility and lighting for any required local operator action; and
- The materiel condition and preservation of systems and equipment.

Finally, the team assessed the conformance of the currently installed system configurations to the current design and licensing bases.

b. Observations and Findings

Inadequate Flooding Protection for The Service Water System

The inspectors identified an unresolved item associated with correctly translating the USAR commitments regarding flood protection for the service water pump room.

USAR Section 2.4.8.2 stated, “The Probable Maximum Flood Water is elevation 583.7 feet...” Section 9.2.1.3 stated, “In the event of high water levels,...the [service water] pump room is sealed to prevent flooding.” Section 3D.1.4, “[GDC] Criterion 4 - Environmental and Missile Design Basis,” stated, “These [safety-related] structures, systems, and components are appropriately protected against dynamic effects...and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit.”

Contrary to these commitments, the service water system was not adequately protected against flooding effects that could result from high lake water levels, from internal flooding, and from other threats to the system that could result from failure of non-seismically qualified equipment as follows:

(1) The three service water pumps were located in a single “sealed” room in the service water pump house. Also located in the same room, immediately adjacent to and staggered between the service water pumps, were two cooling tower makeup (CTMU) pumps, each capable of pumping up to about 15,000 gallons per minute. Neither the CTMU pumps nor the associated piping and equipment were seismically qualified or mounted. The inspectors determined that during a seismic event, the pumps could be dislodged from their mountings. If this were to occur then the CTMU pumps could impact the adjacent service water pump columns and pump motors, resulting in their failure. Additionally, failure of a CTMU pump casing or its associated piping could produce flooding rates which could completely fill the room in approximately two minutes. The service water pump motors would begin to flood at a water level of about five feet above the floor in significantly less time, and the safety-related motor control centers (MCCs) located in this room at approximately one foot off the floor in just seconds. These MCCs provided power for service water system motor operated valves, the safety-related room ventilation fans, the service water strainer motors, and other equipment. Therefore, a seismic event that could cause structural failure of the CTMU pumps or piping could result in rapid loss of both divisions of service water due to mechanical impact or room flooding.

The concern with the seismic qualification of the CTMU piping was identified by the licensee in the LIR and documented on CRs 02-06297 and 02-06139. The issue of the seismic qualification of the CTMU pumps with respect to impact on the adjacent service water pumps and the issue of flooding as a result of the movement of the seismically non-qualified CTMU pumps causing their own casing failure or the failure of the attached piping had not been identified or documented by the licensee's LIR.

(2) The CTMU pumps were equipped with a feature intended to provide protection for the service water system components in the room in the event of cracks or breaks in the CTMU components in the room. The feature was a pressure switch located in the discharge piping of each CTMU pump that was designed to shut down the pump whenever discharge pressure decreased to 20 psig from normal operating pressure, about 50 psig. However, informal evaluations performed by the inspectors and subsequently by the licensee, indicated that break flows of several thousand gallons per minute would be required to reduce the pressure to the shutdown setpoint. At this rate the vital equipment in the room would be flooded in seconds. Therefore, the inspectors concluded that this device was incapable of performing its intended purpose. Additionally, this feature was non-safety, non-1E powered, non-environmentally qualified, and not designed for single failure. Therefore, it did not meet the fundamental design requirements for equipment required to perform a safety function.

(3) The diesel fire pump was located in a space adjacent to the service water pump room but within the same sealed enclosure, and the spaces were connected by a non-watertight door and a ventilation opening in the wall between the rooms. The floor elevation of this enclosure was 576'. The fire pump room contained a drain sump with two non-safety related sump pumps, each equipped with a single non-safety related discharge check valve. A common four-inch discharge line downstream of the check valves penetrated the west wall below the maximum lake flood level (583.7') and was connected to the plant storm drains. These valves were not in any test or inspection program; therefore, they could be considered failed open. Therefore, a design basis flood from the lake could cause backflooding of both rooms through these valves.

An extent-of-condition review, performed at the inspectors' request, in the service water valve room and pipe tunnel located just outside the sealed service water pump room revealed a similar condition. This area, at a floor elevation of 566'-3", was connected to an adjacent water treatment building by a non-watertight door and another ventilation wall opening. This review identified three sumps containing a total of seven sump pumps, each equipped with an unqualified, untested check valve that connected with the storm drains. In this area and below flood elevation, were the safety-related service water valves SW-1395 and SW-1399, which were required to provide isolation of the non-safety related portion of the system for accident conditions. Such flooding could also preclude operator access to these valves for manual isolation.

- USAR Section 3.4.1 stated, "The Seismic Class I service water tunnel may be flooded due to postulated failures of either water treatment structures and systems or failure of Seismic Class II pipe within the tunnel." It goes on to say that, "The Seismic Class I systems within the tunnel are designed to remain operational while flooded." As a result of questions by the inspectors, the licensee identified several non-seismic pipes and components in the service water pipe tunnel/valve room and the connected water treatment structure that had not been evaluated in the flooding analyses; no documentation could be provided that demonstrated the ability of the service water isolation valves SW-1395 and SW-1399 to operate while flooded.

- In response to inspector questions, the licensee performed a review of the service water pump room penetrations that were below the external flood elevation. This review revealed that conduits that terminated at junction boxes below the flood level were not sealed against flooding; the sealing of these junction boxes had been credited for flood protection. However, these boxes were not rated for flood conditions (internal flooding of the box), and their seals could not be reliably assured.

- The inspector's walkdown of the service water system identified another potential external flood source in the service water pump room. CTMU pump number 116-2 was out of service, and the two-inch drain valve from its strainer was danger tagged open. This formed a direct communication between the room and the intake bay through the pump column, the discharge piping, and the strainer. For an external flood, this valve would have allowed the room to be flooded. The Senior Reactor Operator accompanying the walkdown was asked what actions with regard to valve lineup in the room would be required for an external flood, and the response was none. The inspectors then reviewed the plant's external flood procedure, RA-EP-02830, "Emergency Plan Off Normal Occurrence Procedure, Flooding," Revision 00, and found that it had no guidance with respect to verifying proper valve lineup for flood protection, and the licensee's clearance order tagging procedure also did not address this condition.

- One of the documents provided to the inspectors in response to these concerns was Safety Evaluation 96-0078, which addressed potential flooding of electrical duct banks. This document addressed the fact that the then-current USAR indicated that three of the duct banks were enveloped in a waterproof membrane up to the 577'-10" elevation, but in fact, those three, along with the other plant duct banks, were only protected up to 575'. However, the maximum lake flood level was 583.7', and the safety evaluation addressed only the effect that such a flood would have on groundwater table seepage. The safety evaluation incorrectly concluded that groundwater would not exceed 574.5', and therefore, the duct banks were protected. It also incorrectly appeared to assume that the breakwater dike at elevation 591' would protect the general site from the static lake level during such a flood, and therefore it did not address the potential for direct flooding of the duct banks from this source.

The licensee entered the issue into its corrective action program as CRs 02-07714, 02-07782, 02-07760, 02-07569, 02-07746, 02-06297, 02-06139 and screened the CRs as requiring resolution prior to the mode in which SW was required by plant TS (Mode 4). In order to resolve the issue, the licensee will need to perform additional analyses to assess the ability of the licensee's SW pumphouse to withstand internal and external flooding. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01h).

.5 Design Review

a. Inspection Scope

The team reviewed the current as-built instrument and control, electrical, and mechanical design of the selected systems. These reviews included a review of design assumptions, calculations, required system thermal-hydraulic performance, electrical power system performance, protective relaying, and instrument setpoints and uncertainties. The team also performed a single failure review of individual components to determine the effects of such failures on the capability of the systems to perform their design safety functions.

The inspectors reviewed the selected systems including a review of calculations, drawings, specifications, vendor documents, Updated Final Safety Analysis Report, TS, emergency operating procedures, and temporary and permanent modifications.

b. Observations and Findings

Non-Conservative TS Value for the 90 Percent Degraded Voltage Relay

The inspectors identified a Green finding that is being treated as an additional example of a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control, associated with assurance that applicable regulatory requirements and the design basis for structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions. Specifically, the inspectors determined that the TS allowable value for the 4160 VAC, 90-percent Degraded Voltage function as stated in TS Table 3.3-4 was non-conservative.

This table established an allowable setpoint value of $\geq$ 3558 Volts for the 90 percent Degraded Voltage Relay at Davis-Besse Nuclear Plant. Licensee calculation C-EE-004.01-049 established an allowable value for Degraded Voltage at 90 percent of the nominal bus voltage of 4160 V, or 3744 V. The calculation determined this value based upon the minimum voltage value that motor operated valves (MOVs) require to successfully operate. Based upon voltage drop analysis of the Davis-Besse electrical distribution system, the calculation determined that 88.5 percent (3682 V) was the minimum acceptable short-term degraded voltage at the safety related 4160 V buses. The calculation allowed for uncertainties and established additional margin for future application against plant modifications and minor changes. Based upon the calculation, the analytical limit was determined to be 3690 V and the resulting allowable value was established as 3744 V.

While the value calculated appeared to be sufficiently conservative, the inspectors noted that the licensee had not established administrative controls in relation to this issue. While CR 02-06243, documenting the discrepancy between the TS allowable value and the value determined by the calculation, had been issued four days prior to the inspection team arriving on site, the CR concluded that no immediate action was required at that time. Further, the CR recommended that “the calculation procedure should be revised to permit calculation preparers to place calculations that require an event to take place prior to permitting use in ‘Restricted-Hold’ status.” To date, there is no mechanism that permits a calculation to be performed and issued without approving it. This makes it part of the design basis and could have severe ramifications if the calculation data were used in the field. In lieu of having the requirements in the calculation procedure that permit issuance of ‘Restricted-Hold’ calculations, this calculation should be revised to reflect the current licensing basis in the TS.

The inspectors communicated to the licensee that while they had identified the discrepancy between the TS allowable value and the value determined by the calculation, the actions that they had proposed in CR 02-06243 appeared to be inadequate. The inspectors noted that since the value in the calculation was the correct value, administrative actions should be taken to make the operations staff aware that the TS allowable value was incorrect and non-conservative.

Without administrative controls in place to identify the non-conservative TS allowable value for the 90 percent Degraded Voltage Relay, a condition could exist in which the voltage setting for this relay could have been set non-conservatively and still declared operable. With a lower setpoint, motor-operated-valves required for post-accident operation may not have been able to operate when called upon.

10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires that “Measures shall be established to assure that applicable regulatory requirements and the design basis...are correctly translated into specifications, drawings, procedures, and instructions.” Contrary to this requirement, the licensee failed to correctly establish the TS allowable value for the 90 percent Degraded Voltage Relay setpoint.

This finding was determined to be more than minor because it affected the mitigation systems cornerstone objective. This finding screened as Green in the SDP phase 1, since this issue was a design deficiency that was confirmed not to result in loss of function in accordance with GL 91-18 (Revision 1). Because the finding was of very low safety significance, and was captured in the licensee’s corrective action system as CR 02-07766, this finding is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 50-346/2002-014-01i).

Poor Quality Calculation for 90 Percent Degraded Voltage Relay

The inspectors identified an unresolved item associated with use of insufficiently justified, non-conservative uncertainty values in the calculation for the 90 percent Undervoltage Relays.

The inspectors questioned why the licensee did not use vendor-supplied numbers for uncertainties for the 90 percent Undervoltage Relays. Instead, the licensee used uncertainty values associated with a vendor test report for the relay. This test report, however, only provided test data for one tested relay and not for a batch of relays. This resulted in the licensee using smaller uncertainty values in their calculation. The use of these smaller uncertainty values resulted in non-conservative results in the setpoint calculation for the 90 percent Undervoltage Relays.

The licensee entered the issue into its corrective action program as CR 02-07633. In order to resolve the issue, the licensee will need to perform additional analysis to assess the impact of using non-conservative uncertainty values. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01j).

Non-Conservative Relay Setpoint Calculation for the 59 Percent Undervoltage Relay

The inspectors identified a Green finding that is being treated as an additional example of a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," associated with assurance that applicable regulatory requirements and the design basis for structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions. Specifically, the inspectors identified that uncertainties associated with the 59 percent Undervoltage Relay TS allowable setpoint value were non-conservative. Based upon the as-left values and the tolerance band used in the calibration procedures for the relays, this allowed the relays to be calibrated to an upper band that, with the true uncertainties taken into account, allowed the TS upper setpoint to be exceeded.

TS Table 3.3-4 established an allowable setpoint value of ≥ 2071 to ≤ 2450 Volts for the 59 percent Undervoltage Relay at Davis-Besse Nuclear Plant. Therefore, the relays should have been calibrated to a value that, with uncertainties factored in, was within the allowable value's band. Calculation C-EE-004.01-051 established a value for calibration. In the calculation, uncertainty values for M&TE equipment, Potential Transformer (PT) accuracy, drift, and tolerance (band allowed for technician setting the relay) were used to determine the nominal setpoint for the relays.

Since electrical undervoltage relays operate at voltage levels much less than the voltage seen at the 4160 VAC bus, the voltage is stepped down through a PT to allow relay operation. The PT ratio used at Davis-Besse corresponds to a 35 to 1 primary to secondary turns ratio. Thus, at 2450 Volts on the primary side of the PT, the relay would experience a voltage of 70 Volts. With uncertainties taken into account, the relays would need to have been set at a voltage less than 70 volts; however, the relay (type NGV) used at Davis-Besse was not rated for operation below 70 volts. The NGV relay is rated for operation within a band of 70 volts to 120 volts. Since the relay could be physically set below 70 volts, the licensee still used the relay, with a lower setting. The inspectors noted that it is uncertain how this would have affected the relays' operation; however, since operation below rated values could cause additional inaccuracies in the relay, the inspectors determined that an evaluation would need to be performed to determine the effects of operating below the relays' established vendor ratings. This evaluation had not been performed by the licensee.

Additionally, the drift value used by the licensee was based upon observed calibration data performed on relays prior to 1992. The value that was established (+/- 0.5V) was based upon monthly as-found values. Based upon review of monthly functional results on the relays from the past three years, the inspectors discovered that the drift actually exceeded the +/- 0.5V value used in the calculation. In fact, one as-left value showed a drift of 0.9V in the positive direction. Based upon this, the inspectors determined that the drift value that was used by the licensee was poorly established and resulted in the use of a non-conservative drift. Condition Report 02-06737 documented this issue.

The inspectors also questioned the absence of a value for uncertainties associated with temperature effects on the relay. Since temperature effects for the most part were also in the positive direction, the absence of such a value again would be non-conservative. The licensee acknowledged this concern in CR 02-07646.

Additionally, the vendor manual for the NGV relay established an accuracy value for dropout of the relay on undervoltage. Vendor documentation stated, “On any dropout operation, the voltage range from the beginning of the action to its completion is about one percent of rated voltage.” The rated voltage for the NGV relays is 120 volts. Consequently, the accuracy of these relays is 1.2 volts. This meant that if an undervoltage condition were to occur, the relay was not guaranteed to dropout until the voltage reached 1.2 volts below the relay setting. Calculation C-EE-004.01-051 did not account for this accuracy. The absence of this value again resulted in a non-conservative value for the 59 percent Undervoltage Relays.

In accordance with Davis-Besse maintenance/testing procedures for these relays, the upper band for the 59 percent Undervoltage Relay was 68 volts. If the more conservative values had been accounted for in the calculation, and the NGV relay vendor-provided accuracy had been accounted for, this value would have been lower. Additionally, had temperature effects and the operation of the relay outside of its rated band been taken into account, the upper voltage value could have been even lower. By not accurately factoring in all the uncertainties, the licensee’s upper voltage limit allowed the setpoint for the 59 percent Undervoltage Relay to be above the allowable value of 70 volts.

In addition, the results in calculation C-EE-004.01-051 established a Dropout Setting Range for the relay as 65 to 69 volts. The calculation also stated that for operability purposes, “an undervoltage relay whose “as-found” operating voltage if found to be greater than (>) 69.64 volts (2437.4 volts primary) will be considered to be outside the bound of the Technical Specification allowable values.” These conclusions were clearly incorrect.

Not exceeding the upper voltage limit is important, because the undervoltage relay should actuate at a value low enough so that inadvertent power supply transfers can be prevented. Since both divisional sets of undervoltage relays were affected, this could have potentially led to a premature loss of offsite power. However, since each division had four relays for each safety-related 4160-Volt bus, and since the likelihood of an occurrence of the type of limited undervoltage transient that would cause the relays to drop out prematurely is small, the risk significance of this issue is very low.

10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires that “Measures shall be established to assure that applicable regulatory requirements and the design basis...are correctly translated into specifications, drawings, procedures, and instructions.” Contrary to this requirement, the licensee failed to correctly calculate the 59 percent Undervoltage Relay TS allowable setpoint value.

This finding was determined to be more than minor because it affected the initiating events cornerstone objective. This finding screened as Green in the SDP phase 1, since this issue does not contribute to the likelihood of a Primary or Secondary system LOCA initiator, does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available, and does not increase the likelihood of a fire or internal/external flood. Because the finding was of very low safety significance, and was captured in the licensee's corrective action system, this finding is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 50-346/2002-014-01k).

<u>Inadequate Calculations for Control Room Operator Dose (GDC-19) and Off-Site Dose (10 CFR Part 100)</u>

<u>High Pressure Injection Pump Minimum Flow Valves HP31 and HP32</u>

The inspectors identified an unresolved item associated with correctly translating the USAR commitments regarding calculations for General Design Criteria (GDC)19 and 10 CFR Part 100 requirements. The design of the HPI system has a single isolation valve on each of the minimum flow return isolation lines to the borated water storage tank (BWST). The team's review identified inadequate analysis of a single failure of the minimum flow valve return check valve HP31/32 to close during the recirculation phase of a postulated LOCA.

Note 1 of USAR Table 6.3-6 entitled "Single Failure Analysis - Emergency Core Cooling System," stated the following: "The dose rate at the site boundary due to "shine" from the Borated Water Storage Tank (BWST) has been evaluated for this case and found to be 300 mr/hr. This was based on a site boundary minimum distance of 737 meters. The flow through the line to the BWST was assumed to be 500 gallons (expected flow rate is 35 gpm). The activity entering the BWST was the activity in the Containment Vessel Emergency Sump water, containing 50 percent of the core saturation inventory consistent with licensee specifications. This activity was based on an assumed decay for 90 minutes, the time at which the recirculation mode is initiated, based on the worst RCS break (0.1 ft^2) for which the piggyback mode may be required. The dose rate was determined by considering the BWST as a point source conservatively neglecting self-attenuation of the water in the tank and not taking any credit for dilution with water already in the lower portion of the tank."

Assumption 5, Sheet 3 of calculation 35.25, "Dose Rate from BWST," states the following: "The input of the CTMT sump water into the BWST starts at 90 min after the LOCA and lasts 10 min. Input rate is 50 GPM..." This assumption of the total release based on the 500 gallons did not appear to be conservative for the following reasons:

- Use of an assumed 10 minutes for operator action could not be supported because the most limiting single active failure for this scenario is a spurious reopening of one of the minimum flow valve return check valves after valve closure. Due to the lack of a safety grade alarm which indicates mispositioned valves, the basis for the 10-minute assumption could not be validated by the licensee.

- Review of surveillance test procedure DB-SP-03218/03219 showed that the indicated flow was approximately 50 gpm. However, the test configuration is different from the post-LOCA recirculation phase. The test configuration simulated the injection phase, where the HPI pump suction was aligned to the BWST tank. The release configuration takes place in the recirculation, piggyback mode, where the HPI pump suction is aligned to the discharge of the low head injection (LPI) pumps. The discharge head of the LPI/DHR pumps would add to HPI pumps, greatly increasing the discharge pressure, resulting in a significantly higher flow than 50 gpm.

- The assumption of a 90-minute delay was also non-conservative. Emergency procedure DB-OP-02000 stated that the piggyback mode would be used for all LOCAs which result in LPI flows less than 1100 gpm. The 90-minute assumption appears to be based on the no LPI flow time calculation. USAR Section 6.3.2.11, Reliability Considerations, states: "Since LPI injection is not flowing in this situation, it will take at least 100 minutes to empty the BWST with both HPI and Containment Spray pumps running at design capacity, which gives the operator an ample amount of time to determine the need for, and to perform the required actions. Motor operators on the valves and hand switches in the control room are installed to allow alignment from the control room." Based on the usable BWST volume of 360,000 gallons and combined LPI flow of 2,200 gpm, the time at which recirculation will take place is estimated to be approximately 60 minutes or less (depending on the level and LPI flow instrument accuracy, actual containment spray flow vs. the design flow, etc). Thus, a 90-minute delay is not conservative.

- The miniflow return line is located near the top of the BWST. During the event of interest, the BWST level is significantly below the point of the return pipe entry. The jet of a high pressure liquid at the temperature of about 200°F exiting the pipe nozzle inside the tank will have an appreciable fraction of its liquid flash to vapor along with the entrained gases. The remaining liquid could have a large surface area as it travels downwards, liberating the remaining gases which have partial pressures below the tank atmosphere. Thus the USAR statement and calculation assumptions of iodine coming out of solution are correct and not overly conservative, contrary to the statement made in the calculation.

Therefore, the critical inputs used for dose calculation (the assumed volume and the activity decay time) appear to be non-conservative.

The calculation was silent on the impact on the GDC 19 limits. Part B of the calculation dealt with the gaseous release.

The licensee issued CR 02-06701 to document the team's concern. This CR noted that, "...this issue involves past operability issues and must be considered a restart issue."

The inspectors questioned the licensee if the site boundary release described in Note 1 of USAR Table 6.3-6 was incorporated in the 10 CFR 100 or the GDC 19 calculations. Based on this question and other related team questions, the licensee issued

CRs 02-07701 & 02-07713, which identified problems related to GDC 19 and 10 CFR Part 100 calculations (see discussion below).

The licensee screened the three CRs as requiring resolution prior to the mode in which ECCS was required by plant TS (Mode 4). In order to resolve the issues, the NRC will need to assess the licensee's reevaluation and the impact of the calculational deficiencies on the GDC-19 and 10 CFR Part 100 regulatory limits. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01l).

Other GDC 19 and 10 CFR 100 Issues

The inspectors identified an unresolved item associated with correctly translating USAR commitments regarding calculations for GDC-19 and 10 CFR Part 100 requirements. The inspectors' review of the surveillance test procedures, USAR, calculations and discussions with the licensee determined that the USAR calculated offsite dose was based on an ECCS leakage rate of 1.6 gallons per hour (gph) while the allowable leakage rate was based on 40 gph.

USAR Section 3.6.2.7.1.11 discusses a pump seal failure 24 hours after a LOCA with an assumed leak rate of 120 gpm. However, offsite dose calculations and control room dose calculations for this postulated passive failure were not calculated. Some of the (iodine) releases from this postulated leak would be in the ECCS pump rooms, which were ventilated through safety grade charcoal filters. However, the iodine remaining in the solution could come out of the system after it has been pumped to the radwaste system. A leak in this area would be through a path outside of the ECCS pump room ventilation filters. Also, the radwaste storage tank is not seismic and releases from the area would not be filtered. It should be noted that calculation 36.28, "ECCS - Pump Seal Failure," Revision 0, determined the maximum acceptable leakage rate through the pump seal as 82.7 gpm based on the control room dose (GDC 19). In response to the team's question as to whether this calculation was current or superceded, the licensee responded that no calculation that superceded calculation 36.28 could be located.

In response to the team's concerns described above, the licensee issued CR 02-07713. This CR documented the above concerns and also stated the following:

> "In general, the dose contributions expected from these sources is not large compared to other accident dose. However, in a fairly short review time, the above issues were all identified. Therefore, as noted above, a thorough extent of condition review should be performed to look for identification of all required accident dose contributors and consistent treatment of accident dose contributions."

Additionally, CR 02-07713 documented that the control room operator doses evaluated in USAR Section 15.4.6 were based on only the containment leakage contribution. The doses resulting from expected fluid leakage from the ECCS post-LOCA were not addressed. NRC Regulatory Guide 0737 requires such an evaluation to be performed.

The licensee screened CR 02-07713 as requiring resolution prior to the mode in which ECCS was required by plant TS (Mode 4). In order to resolve the issue, the licensee will need to assess the impact of the calculational deficiencies on the GDC-19 and 10 CFR Part 100 regulatory limits This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01m).

HPI Pump Operation Under Long Term Minimum Flow

The inspectors identified an unresolved item associated with adequately assessing HPI pump operation under long term minimum flow. The team reviewed the licensee's response to NRC Bulletin 88-04 which directed licensees to evaluate the capability of safety related pumps to run at minimum recirculation flow rates. For the HPI pumps, the licensee had concluded that the supplied minimum recirculation flow was adequate. The licensee had contacted the HPI pump vendor for information and the vendor responded that, while there was no definitive data that would raise doubts concerning the HPI pump miniflow, they were unable to confirm that these flows were adequate to ensure that HPI pumps would not experience degradation as a result of the impeller recirculation. The vendor further recommended that a pump test to verify the endurance be conducted under actual miniflow conditions.

The licensee subsequently performed a test, which indicated low vibration readings when in the minimum recirculation mode. The team's review of the test determined that the test conditions appeared to be non-conservative. The test had been performed at normal ambient temperature using BWST water which simulated the injection phase of the accident rather than the recirculation phase which would experience significantly higher fluid temperatures and possibly debris. Additionally, this was a one-time-only test, hence, the effects of degradation, wear, and tear were not addressed. The licensee's assessment also did not address the allowable duration of operation at a minimum flow condition. Based on the team's questions, the licensee issued CR 02-07684. This CR noted that "...due to the importance of the pumps to perform their functions, and the potential for extended periods of operation on minimum recirculation mode, this issue should be considered a mode 3 restart constraint."

The licensee screened CR 02-07684 as requiring resolution prior to the mode in which ECCS was required by plant TS (Mode 4). In order to resolve the issue, the licensee will need to assess the ability of the HPI pumps to perform as intended during extended operation on minimum flow. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01n).

HPI Pumps Minimum Flow, Unanalyzed SBLOCA Sizes

The inspectors identified an unresolved item associated with analyzing some small break LOCA (SBLOCA) sizes. The inspectors' review of the USAR and discussions with the licensee determined that the SBLOCA analysis covered a spectrum of breaks starting at 0.01 sq. ft. USAR Sections 15.3.1.1 states "Depending on the break location and imposed boundary conditions, a break area can be identified for which the HPI or normal makeup system is capable of matching the leak rate ensuring an orderly shutdown. For example, the leak rate resulting from the rupture of a 3/4" schedule 160 instrument line (0.002 ft^2) is matched by the normal makeup system about 1000 seconds into a postulated accident without a complete loss of the pressurizer liquid level." The HPI pump minimum flow recirculation valves are closed prior to transferring to the containment emergency sump following a loss of coolant accident (LOCA). If the HPI pumps are not assured of injecting sufficient water into the Reactor Coolant System, the pump flow may not be adequate for thermal protection (reference NRC Bulletin 88-04 minimum flow issues).

An example condition where this could be problematic is for very small break LOCAs that later repressurize the RCS above the HPI shut-off head. An additional issue involves performance of the water lubricated outboard bearing when on containment sump recirculation. The concern is that at low flow rates, the bearing load may be higher and the bearing could be less tolerant of debris.

The licensee contacted the NSSS vendor for discussion of smaller break sizes, between the capacity of the makeup system and up to the 0.005 ft^2 range, which were not covered by the existing SBLOCA analyses. For these breaks, the vendor could not discount the possibility of intermittent repressurization that would challenge the minimum HPI pump flow requirements for both HPI trains.

In summary, the spectrum of the SBLOCA breaks from 0.002 to 0.01 sq. ft. breaks was not analyzed and the impact on the HPI pumps' ability to perform their safety-related function was unknown prior to the inspector's questions. This scenario could simultaneously affect both HPI trains, without any additional postulated single failures. This CR noted that "This issue needs to be resolved prior to restart."

Based on the inspector's questions, the licensee issued CR 02-06702 and screened the CR as requiring resolution prior to the mode in which ECCS was required by plant TS (Mode 4). In order to resolve the issue, the licensee will need to assess the ability of the HPI pumps to perform as intended during extended operation on minimum flow. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01o).

Inadequate Service Water System Flow Analyses

The licensee and the inspectors identified an unresolved item associated the licensee's SW system flow analysis in properly accounting for a number of required conditions. The latest service water system flow calculation of record that was intended to demonstrate the ability of the system to deliver the design basis flows to the various service water system safety-related loads was C-NSA-000.00-017, "PROTO-FLO Service Water System Model." The inspectors reviewed this calculation and found that it non-conservatively did not account for the following:

- The lowest acceptable service water pump performance (the calculation utilized the original vendor performance curves with no degradation margin).
- Single failure of the forebay return valve SW-2930 to open, which required opening SW-2929 in order to use deicing return flowpath, which was the highest resistance pathway.
- Design basis strainer resistance.
- Strainer blowdown losses.

- Back leakage through service water pump discharge check valves (test acceptance criterion for these valves was that back flow would not cause idle pump rotation which, in fact, would require flows of several hundred gpm).
- Design basis lowest ultimate heat sink (UHS) level.
- Providing the safety-related water source for the auxiliary feedwater system.
- Removal of various check valve internals (valves were modeled as straight pipe).

Therefore, the ability of the system to provide the required design basis flows to the safety-related heat exchangers could not be verified.

All of these deficiencies except for the pump discharge check valve leakage were also identified by the licensee in the LIR and documented in CR 02-06438. Some were also re-identified in the licensee's Safety System Design and Performance Capability (SSDPC) self-assessment and documented in CRs 02-6333 and 02-07745.

The licensee screened the three CRs as requiring resolution prior to the mode in which the SW system was required by plant TS (Mode 4). In order to resolve the issue, the licensee will need to assess the service water system flow requirements against the yet-to-be-performed analyses that demonstrate the ability of the system to provide the required flows to safety-related loads under design basis conditions. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01p).

Definition of Passive Failure

During the review of the single-failure effects in the SW system, the inspectors postulated a passive failure in valve SW-82. The inspectors requested the licensee's analysis for assuming that valve SW-82 failed closed and could not be reopened; for example, if the valve had a stem-to-disc separation. The licensee stated that other failures of valve SW-82 had been assessed previously and documented in PCAQR 91-0611, but that they did not consider a stem-to-disc separation as either credible or required to be assumed as part of a passive failure analysis.

The inspectors disagreed with the licensee's position that stem-to-disc separation was not credible and also disagreed with the licensee's position that stem-to-disc separation was not required to be assumed as part of a passive failure analysis.

This matter will be referred to the Office of Nuclear Reactor Regulation. Pending the results of that deferral this item will remain unresolved (URI 50-346/2002-014-05).

Inadequate Service Water System Thermal Analyses

The inspectors identified an unresolved item associated with the licensee's SW system thermal analysis properly accounting for a number of required conditions. The inspectors reviewed several calculations that were intended to establish the design basis temperature profile for the Ultimate Heat Sink (UHS). The UHS temperature profile information generated in these calculations was required as an input to the SW heat exchanger thermal performance calculations, which were intended to demonstrate their ability to remove their design basis heat loads without exceeding their individual design temperature limits.

The inspectors identified a number of non-conservatisms (listed below) in the UHS calculations and in the measurement of service water temperatures. As a result, the calculated time-dependent service water temperature profile, which was input to all of the SW system heat exchanger performance analyses, was determined to be non-conservative:

- The UHS analyses did not consider a postulated single failure-to-open of the forebay return valve, SW-2930. Failure of valve SW-2930 to open is the worst case system lineup with respect to SW system temperature profile, since it would redirect service water to the forebay through the deicing line. This flowpath returned the heated service water directly in front of the service water pump house trash bars rather than at the opposite end of the forebay, which was the "normal" post-accident return discharge point. Therefore, the returned water had a much lower heat rejection opportunity than from the "normal" return point.

- The licensee had analyzed the deicing flowpath and determined a higher UHS temperature profile would result. The forebay return path resulted in a peak of 112.6°F instead of 107.6°F for the "normal" accident flowpath; however; only the lower value was used as input for all service water heat exchanger calculations. An additional non-conservatism was that the calculation only considered the "clean pond" condition, (i.e., with no silting).

- Calculation 12501-M-00004, "UHS Pond Performance Analysis - Max Evaporation - Silting," addressed the UHS thermal performance and volume for 1.5 feet of silting in the forebay; however, it did not consider the deicing return flowpath.

- The design basis initial service water temperature used for all heat exchanger analyses was 90°F. This was reflected by TS 3.7.5.1.b, which limited the UHS temperature (not service water temperature) to an "average" of ≤90°F. A single instrument was used for determining compliance with this TS. It was located in front of the service water pump house trash bars, approximately two feet above the pond bottom. However, as early as 1995, the service water system supply header temperature had been measured with very accurate measurement and testing instrumentation (M&TE) at approximately 1.5°F to 2°F warmer than the readings from the TS instrument. This information indicated three non-conservatisms with the service water heat exchanger analyses and the UHS thermal analyses as follows:

    - With the indicated UHS temperature at the TS 90°F limit, the actual temperature entering the heat exchangers could be as much as 2°F higher than the analyzed condition, significantly reducing their performance, potentially below design basis values.

    - All UHS pond analyses started with an assumed *uniform* pond temperature of 90°F. The observed temperature offset during normal operation between the

UHS pond temperature near the bottom and the service water header temperature indicated that the service water delivered to the heat exchangers was a mixture of warmer, upper-strata pond water with the cooler near-bottom water. Therefore, the temperature as read from the TS instrument was also not indicative of the “average [UHS] water temperature” as required by the TS. Rather the true “average” UHS temperature was somewhat higher than the monitored temperature at the TS instrument. Therefore, the UHS analyses contained non-conservative initial temperatures with respect to the indicated TS value.

- The UHS analyses were based on a time-dependent model that started with uniform pond temperature at 90°F, and the hotter returning service water entering the pond near the surface and displacing the uniform temperature water downward toward the entrance to the intake structure. However, this was a non-conservative model with respect to the actual stratification indicated by the temperature observations. With stratification existing during normal operation, hotter water would reach the service water intakes sooner than the model predicted for accident conditions.

• None of the UHS analyses accounted for the spent fuel pool (SFP) heat load which is initially shed from the component cooling water (CCW) system (cooled by service water) early in an accident, but must be restored by operator action at a later time to prevent exceeding the SFP design temperature, 150°F. The design basis analyses indicated that the fuel pool would not only exceed 150°F very quickly, but would reach boiling within ten hours of loss-of-cooling (SFP heat load was significantly increased with the high density fuel storage modifications). There were no analyses that addressed the structural or leak-tight integrity of the SFP, the thermal-hydraulic capability, e.g., restart capability of the SFP cooling system, or the ability to provide makeup to the SFP for conditions beyond its design basis temperature. The inspectors estimated this additional heat load at eight to ten million BTUs per hour.

• The inspectors also identified that the ECCS pump room temperature analyses, Calculation 12501-M-003, “ECCS Pump Room Temperature,” did not consider the probable worst-case heat loads from pump motors and piping that would be associated with the high pressure injection (HPI) pumps operating in the piggyback mode.

Therefore, the ability of the service water system to provide the required design basis heat transfer thermal conditions for the safety-related heat exchangers could not be verified.

The licensee entered the issue into its corrective action program as CRs 02-05372, 02-06177, 02-06332, 02-06336, 02-06370, 02-07004, and 02-07716 and screened the CRs as requiring resolution prior to the mode in which the SW system was required by plant TS (Mode 4). In order to resolve the issue, the licensee will need to assess the service water system thermal requirements. This issue will remain unresolved pending the licensee’s evaluation and the NRC’s review (URI 50-346/2002-014-01q).

Inadequate Ultimate Heat Sink Inventory Analyses

The inspectors identified an unresolved item associated with the licensee's UHS inventory analysis properly accounting for a number of required conditions. USAR Section 9.2.5.1, "Loss of Intake Canal," stated, "The water stored in the intake forebay below elevation 562 feet will provide sufficient cooling surface to continue cooling the station by evaporation for at least 30 days." The inspectors determined that the plant's UHS water inventory analysis of record, Calculation 12501-M-00004, "UHS Pond Performance Analysis - Max Evaporation - Silt," did not adequately account for the following water loss pathways:

- During normal operation the service water system return water is routed through valve SW-2931 to the plant cooling tower to provide its makeup (this routing does not return the water to the UHS). In order to preserve UHS water inventory during accident conditions, this valve is closed, and the water is returned to the UHS (either through the forebay return valve SW-2930, or if it has failed to open, through the deicing return valve SW-2929). However, the single failure of the cooling tower return valve to close on demand would cause a substantial water loss from the UHS through this pathway (30 inches diameter) that was not accounted for in the calculation.

  USAR Section 9.2.1.2 stated that for this condition, the operator could manually close SW-2931 within three hours. However, this statement was valid only for an electrical failure where the operator could manually close the valve, but would not necessarily be valid for a mechanical failure. Additionally, the existing analyses did not account for even this three-hour water loss.

- The only safety-related water supply for the auxiliary feedwater (AFW) system was the service water system. However, the licensee did not account for UHS water loss through this pathway for events that would require AFW operation. For such events, it was assumed that the non-seismically qualified condensate storage tank (CST) would supply AFW, with no decay heat or reactor coolant system (RCS) sensible heat rejected to the UHS for thirteen hours. This was a non-conservative assumption; there would be more net inventory loss from the UHS with the AFW supply from the service water system than from the CST.

- Evaporation losses were based on the incorrect UHS temperatures described earlier in the report. With higher actual UHS surface temperatures, evaporation losses would be higher than calculated.

Therefore, the ability of the UHS to provide the required design basis inventory to support operability of the service water system for the required 30 days could not be verified.

The licensee entered the issue into its corrective action program as CRs 02-05986, 02-06332, 02-06336, and 02-07692 and screened the CRs as requiring resolution prior to the mode in which the SW system was required by plant TS (Mode 4). In order to resolve the issue, the licensee will need to assess the impact of the calculational deficiencies on the ability of the UHS to perform its intended function. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01r).

No Valid Service Water Pump Net Positive Suction Head Analysis

The licensee identified an unresolved item associated with a lack of a valid net positive suction head analysis for the SW pumps. USAR Section 9.2.5.1 contained a discussion of the adequacy of the service water pumps' net positive suction head (NPSH) for all design basis conditions. However, the licensee could provide no valid design basis analysis that demonstrated this adequacy and the adequacy of the pump submergence with respect to vortex prevention. Additionally, even if such an analysis had been available, it would have likely been rendered non-conservative by the previously described issues related to non-conservative UHS water inventory and temperature analyses. Therefore, the ability of the system to perform its design basis safety function for all conditions of reduced available NPSH and pump submergence within the design bases could not be verified.

This concern was also identified by the licensee in the LIR, documented on CR 02-05923, and screened as requiring resolution prior to the mode in which the SW system was required by plant TS (Mode 4). In order to resolve the issue, the licensee will need to assess the impact of the licensee's failure to correctly translate the USAR commitments with respect to adequacy of service water pumps' NPSH and vortex margin into analyses demonstrating adequacy. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01s).

Inadequate Service Water System (and Other Systems) Overpressure Protection

The design of the service water system was performed under the requirements of ASME Code, Section III, Article NB-7000, "Protection Against Overpressure." Paragraph NB-7155 required that "Individual pressure-relief devices shall be installed for the overpressure protection of components which are isolable from the normal system overpressure protection." Contrary to this requirement, none of the service water system individual heat exchangers and associated piping that were isolable from the system were provided with individual overpressure protection. Other safety-related system heat exchangers, such as the decay heat removal and diesel generator jacket water heat exchangers, were also found to not be provided with individual overpressure protection devices.

Paragraph NB-7153, "Provisions When Stop Valves are Used," required, "No stop valve or other device shall be placed relative to a pressure-relief device so that it could reduce the overpressure protection below that required by these rules, unless such stop valves are constructed and installed with positive controls and interlocks so that the relieving-capacity requirements of NB-7400 are met under all conditions of operation of both the system and the stop valves." Contrary to this requirement, many of the safety-related components in the plant that were provided with relief devices also had manual isolation valves between the components and the relief devices.

These conditions were identified by the inspectors as a result of review of Modification 94-0009, "Service Water Thermal Relief Valve Replacement for

Containment Air Coolers [CACs]," which removed these valves from the CACs and did not replace them. These valves had been initially installed by Modification 88-0234, "Overpressure Protection for the Containment Air Coolers," when it was determined that the coolers were not originally provided with relief valves and, therefore, did not meet Code requirements, as documented in PCAQR Number 88-0737. Discussions with licensee engineers determined that this condition extended to other plant systems and also that some of the relief valves that were installed had the prohibited isolation valves.

The licensee maintained that these conditions were acceptable based on their interpretations of the Code. These interpretations and the inspector's responses follow:

On the concern of relief protection not provided:

- The licensee maintained that the heat exchangers in question were not designed to the Code. However, the attached non-isolable piping was; therefore, by default, in the inspector's view, they were required to meet Code requirements.

- The licensee stated that heat exchangers in "operation" were not isolated and thus could not be thermally overpressurized; therefore, they were not required to be protected. The licensee also stated that heat exchangers not in "operation," i.e., not performing their cooling function but still filled with water, were not required by the Code to be protected. Therefore, per these interpretations, relief protection was never required for heat exchangers and associated piping under any condition, whether in operation or not. The only other condition that could exist was - not in operation and not filled with water, in which case, relief protection was not required. Therefore, there was no condition - in operation, out of operation, or completely disabled - for which the Code was applicable, which defied the obvious intent of the Code. As reflected in Paragraph NB-7155, a heat exchanger is in "operation" when it is "completely filled with water," regardless of whether it is in service or not, or isolated or not. The Code's only concern is whether the component is "isolable," because that was the only condition when the "potential" to be overpressurized by isolation exists.

  The conditions of concern for which the Code requirements were created were for when heat exchangers and associated piping were filled with liquid (incompressible), when they were isolated or could be required to be isolated, for instance, as part of their operational mission, and therefore, when they could be subjected to heating that could cause overpressurization. Many safety-related heat exchangers and associated piping fell into these categories because they could be in standby and fully isolated during normal operation, or partially isolated and could be required by accident conditions to become fully isolated, such as the CACs, which may be required to be fully isolated for containment isolation. Additionally, isolation of the CACs for maintenance could subject them to undetected overpressure that could compromise their leak tightness, which is one of their safety functions as a containment barrier.

- The licensee maintained that heat exchangers were protected from overpressure by plant procedures that prevented them from being isolated when they were filled. However, the Code made no allowances for such administrative controls. The licensee, however, stated that Paragraph NB-7153's allowance of “positive controls” permitted the use of administrative controls in lieu of protection devices. The inspectors disagreed for two reasons: first, that paragraph was applicable only to the use of stop valves between relief devices and the components being protected (which is addressed with the next concern), not valves that isolate the components from the system. Second, in the context of that paragraph and all of Article NB-7000, “controls” clearly refers to “instrumented control” devices, not administrative controls. For example, the last sentence in this Code paragraph discussed verification testing of such “controls,” which could not be appropriately applied to administrative controls.

- The licensee stated that not having such devices could, at worst, result in slight yielding of the components. Such yielding is not allowed by the Code for design conditions for such components.

- The licensee stated that isolated heat exchangers other than the CACs could not be subjected to temperatures nearly as high as the CACs, and therefore, would not experience high stresses. Contrary to this, industry experience has shown that heat exchangers filled solid with water can be subjected to very high stresses and failure with relatively small temperature changes.

Regarding the concern of isolation valves between the protected components and the relief devices:

- The licensee stated that isolation valves were allowed between the relief devices and the components being protected by Paragraph NB-7153, as long as they were administratively “controlled.” However, as discussed above, the only “controls” allowed by this paragraph were control devices that were “constructed” and “installed.” In common parlance, administrative controls cannot be “constructed” and “installed” and their “operability” cannot be “verified by test,” as also required by this paragraph.

In response to the inspectors’ concerns, the licensee generated CR 02-06860.

The licensee disagreed with the inspectors’ observations and stated that to their knowledge they were in compliance with all code requirements. This matter will be referred to the Office of Nuclear Reactor Regulation. Pending the results of that deferral this item will remain unresolved (URI 50-346/2002-014-06).

<u>Service Water Source Temperature for Auxiliary Feedwater System</u>

The inspectors identified an unresolved item associated with the licensee’s analysis for the elevated temperature effects on the AFW system. Section 9.2.1.1, of the USAR “[Service Water System] Design Basis,” states that, “The service water system also provides a backup source of water to the auxiliary feedwater [AFW] system...” Although the condensate storage tank was the preferred water source because of its high water quality, this tank was not seismically qualified. The service water system, therefore, provided the seismically-qualified, safety-related backup water source. The inspectors determined that the service water source for AFW had not been analyzed with respect to its potentially higher temperature condition for various design basis events and the possible impact on the ability of the AFW system to perform its safety function. Such effects could include reduced heat absorption capability for AFW injected into the steam generators and inadequate cooling of AFW lubricating oil. Therefore, the ability of the AFW system to perform its safety function using the service water source for all design basis events for which it may be required could not be verified.

Elements of this concern were identified by the licensee's LIR in CR 02-06107. The licensee entered the entire issue into its corrective action program as CR 02-05923 and screened the CR as requiring resolution prior to the mode in which the SW system was required by plant TS (Mode 4). In order to resolve the issue, the licensee will need to assess the impact of the increased SW temperature on the operability of the AFW pumps. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01t).

Short Circuit Calculations

The inspectors identified an unresolved item associated with the licensee's analysis for postulated short circuits. During the performance of the original calculations the licensee used normal operating voltages instead of maximum voltages. At the higher voltages some results may no longer be acceptable (e.g., if rated for 25,000 amps (25 kva) it may now see 26 kva). This could result in some breakers not tripping and causing the fault to propagate upwards to the 13.8 kv buses. The licensee had identified this issue about a year ago, but the observation was being treated as an administrative issue only. In fact, if a fault propagated upward, the fault could end up resulting in a loss of both normal power supplies.

The licensee entered the issue into its corrective action program as CRs 02-06837 and 02-06302 and screened the CRs as requiring resolution prior to the mode in which the 4160VAC was required by plant TS (Mode 4). In order to resolve the issue, the licensee will need to assess the impact of the higher voltages on the licensee's short circuit calculations and the effect upon the safety-related 4160VAC buses. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-01u).

Inadequate Analytical Basis for the Setpoint to Swap Service Water System Discharge Path

The inspectors identified a Green finding that is being treated as an additional example of a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," associated with assurance that applicable regulatory requirements and the design basis for structures, systems, and components were correctly translated into specifications, drawings, procedures, and instructions when licensee personnel could not find an analytical basis for the setpoint to swap service water system discharge path.

The service water system discharges into one of four paths. Two of these paths (cooling tower makeup and the collection box) were not seismically qualified and provisions were made in the design of the system to automatically divert flow to the seismically qualified discharge lines (intake forebay and intake structure) in the event of obstruction of one of the non-seismic lines. The setpoint for the swapover is 50 psig. The inspectors asked licensee personnel for the calculational bases for this setpoint. Licensee personnel could not locate an analysis.

Not having an analytical basis is of concern for two reasons. First, the plant could have experienced a seismic event which did not fully obstruct the discharge path for service water such that pressure would have been slightly less than the 50 psig setpoint and flow would have been choked down. This extent of flow reduction should have previously been evaluated to demonstrate the ability of the service water system to provide sufficient cooling capability to survive a safe shutdown earthquake. Second, a passive failure causing a similar flow reduction as above could have gone undetected during an event which required design service water flow and design service water flow would not have been demonstrated to be available. A suitable analysis which demonstrates acceptability in these conditions was needed. The inspectors determined that the failure to have an analysis which demonstrates acceptability of conditions with service water discharge header pressure elevated higher than normal and up to the swapover setpoint could affect the design function of the service water system.

10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires that "Measures shall be established to assure that applicable regulatory requirements and the design basis...are correctly translated into specifications, drawings, procedures, and instructions." Contrary to this requirement, the licensee failed to provide a basis for the setpoint to swap the service water system discharge path.

The inspectors considered this finding more than minor because it could affect the mitigating systems cornerstone objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences attributable to design control. Using the significance determination process, the safety significance was determined to be very low (Green) because the finding did not screen as potentially risk significant due to a seismic, fire, flooding, or severe weather event. This violation is being treated as a Non-Cited Violation (NCV 05000346/2002-014-01v) because of the very low safety significance of this condition and because licensee personnel entered this finding in the corrective action program as CR 02-07802. This condition report documents licensee personnel's intentions to check the adequacy of the setpoint.

.6 Safety System Inspection and Testing

a. Inspection Scope

The team reviewed the program and procedures for testing and inspecting designated components of the selected systems. The review included the results of TS required surveillance tests and ASME Code required quarterly in service tests conducted since 1994.

b. Observations and Findings

HPI Quarterly Surveillance Test Instrumentation Issues

The inspectors identified a minor Violation of 10 CFR 50, Appendix B, Criterion XI, Test Control. Specifically, the inspectors' review of the HPI pump quarterly tests identified that the procedures specified M&TE instrumentation to be installed to improve the accuracy of the test. The procedures' specified three allowable instrument ranges for HPI pump discharge pressure; however, two of the three specified instrument ranges (0-2500 psig, 0-3000 psig) were non-conservative when compared to the instrumentation range (0-2000 psig) and readability specified in calculation C-NSA-052.01-003, "HPI Pump Acceptance Criteria," prepared in support of the above test procedures. Based on this discrepancy, the licensee issued CR 02-07466.

10 CFR 50, Appendix B, Criterion XI, requires, in part, that adequate test instrumentation is available and used. Contrary to this requirement, the licensee specified non-conservative instrumentation ranges in the HPI quarterly surveillance test procedure.

This finding screened as minor because the impact of the non-conservative test instruments upon the readings was minimal. Although the failure to specify the appropriate test instrumentation will be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the USNRC's Enforcement Policy.

SW Surveillance Test Does Not Use Worst Case Values

The inspectors identified a Green finding that is being treated as a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control." Specifically, the inspectors identified that the service water train valve test did not appear to demonstrate that worst-case post-accident conditions were bounded. Based on the team's questions, the licensee issued CR 02-07781 which provided a detailed discussion of the shortcomings of the procedure which included lack of trending, failure to declare the valve(s) inoperable, etc.

10 CFR Part 50, Appendix B, Criterion XI, Test Control, requires, in part, that testing be performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. Contrary to this requirement, the service water train valve test did not appear to demonstrate that worst-case post-accident conditions in design documents were bounded.

This finding was determined to be more than minor because it affected the mitigation systems cornerstone objective. This finding screened as Green in the SDP phase 1, since this issue was a testing deficiency that was confirmed not to result in loss of function in accordance with GL 91-18 (Rev. 1). Because the finding was of very low safety significance, and was captured in the licensee's corrective action system as CR 02-07781, this finding is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (Section 1R05.02) (NCV 50-346/2002-014-02a).

ECCS Sump Pump Test Acceptance Criteria

The inspectors identified a minor violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control." USAR Section 3.6.2.7.1.14 states that the capacity of each ECCS room sump pump is approximately 75 gpm. USAR Sections 3.6.2.7.1.8 and 3.6.2.7.1.10 state that the submersible duplex sump pumps in rooms number 105, 113, and 115 have a total capacity of approximately 150 gpm (75 gpm per pump). This is greater than the assumed 120 gpm DHR seal leakage. The team's review of the ECCS Sump Pump Flow Check, DB-SP-04162 identified that its acceptance criterion was 50 gpm per pump. In addition, the test does not verify whether water is pumped from sump to sump (via leaking check valves) or to the intended tank. Based on the team's questions the licensee issued CR 02-07741, which stated that this issue "should be considered a restart issue."

10 CFR Part 50, Appendix B, Criterion XI, "Test Control," requires, in part, that testing be performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. Contrary to this requirement, the acceptance criteria for the ECCS Sump Pump Flow Check was incorrect.

This finding screened as minor because the actual ECCS sump pump performance was determined to be approximately 75 gpm. This was greater than the largest assumed ECCS leakage in the drainage area. Although the failure to utilize an appropriate test acceptance criterion will be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the USNRC's Enforcement Policy.

Inadequate Service Water System Flow Balance Testing

The inspectors identified an unresolved item associated with the licensee's SW system flow balance testing procedure properly accounting for a number of required conditions. Surveillance Procedures DB-SP-03000 and 03001, "Service Water Integrated Train I(II) Flow Balance Procedure," were performed every refueling outage to balance the system flows. The inspectors identified that this procedure did not establish flows to the safety-related heat exchangers based on worst-case design basis conditions, such as degraded service water pumps, lowest UHS level, highest resistance SW system lineup, system resistance degradation, etc. Further, no analyses existed that established the test acceptance criteria for design basis conditions. Therefore, the flow balance procedure did not verify that the system was capable of providing the required flows to its safety-related heat exchangers under design basis conditions.

Additionally, the inspectors noted that standard plant practice was to inspect the system at the beginning of each refueling outage and to perform maintenance as required to remove sediment, clean heat exchangers, and other system performance-improvement maintenance activities prior to performing the flow balance. No analyses had been performed of the as-found conditions. Therefore, the flow balances demonstrated the system's operability only in the newly cleaned, groomed condition.

The licensee entered the issue into its corrective action program as CR 02-06064 and screened the CR as requiring resolution prior to the mode in which the SW system was required by plant TS (Mode 4). In order to resolve the issue, the licensee will need to assess the impact of the as-found SW flow balance against the revised analysis being performed by the licensee. This issue will remain unresolved pending the licensee's evaluation and the NRC's review (URI 50-346/2002-014-02b).

Inadequate Corrective Actions for Service Water Pump Discharge Check Valves

The inspectors identified a Green, Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI when licensee personnel failed to take proper corrective action to correctly change the acceptance criterion for the inservice full flow test for the service water pump discharge check valves to a proper value when it was determined to be non-conservative.

The ASME Code requires check valves to be tested to either the full open position or to the position required to perform their safety function. Prior to 2002, licensee personnel were testing the service water pump discharge check valves for their inservice test for the forward flow direction with an acceptance criterion which required system flow to exceed 9300 gpm to pass the test. An internal audit by Quality Assurance personnel noted that this acceptance criterion was non-conservative. As a result, the acceptance criterion was changed to 10,000 gpm in February 2002.

The inspectors questioned licensee personnel about the basis for the acceptance criterion since in the USAR a design flow of 10,250 gpm was specified. Licensee personnel acknowledged the discrepancy and initiated condition report CR 02-07657 to address it. The explanation was that when licensee personnel made the initial change to the acceptance criterion for flow, they had not taken all available information into account when choosing the new setpoint. The inspectors determined that the failure to choose a proper acceptance criterion for the inservice full flow test for the service water pump discharge check valves could lead licensee personnel to accept test results which would not ensure that the check valve was capable of passing its safety function flow.

10 CFR Part 50, Appendix B, Criterion XVI requires in part that measures shall be established to ensure that conditions adverse to quality, such as non-conformances were promptly identified and corrected. Contrary to the above, in February 2002, licensee personnel did not properly correct the acceptance criterion for the service water pump discharge check valves inservice full flow test when they first recognized it was not correct.

This finding was more than minor because it could affect the mitigating systems cornerstone objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences attributable to poor maintenance procedure quality. Using the significance determination process, the safety significance was determined to be very low (Green) because the finding did not screen as risk significant due to a seismic, fire, flooding, or severe weather event. This violation is being treated as a Non-Cited Violation (NCV 05000346/2002-014-03d) because of the very low safety significance of this condition and because licensee personnel entered this finding in the corrective action program as CR 02-07657.

4OA6 Meetings

Exit Meeting Summary

The NRC inspectors presented the results of this inspection during exit meetings with Mr. L. Myers and other members of licensee management on November 13, 2002. The licensee acknowledged the findings presented. Inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

KEY POINTS OF CONTACT

Davis-Besse

L. Myers, Chief Operating Officer
R. Fast, Plant Manager
T. Chambers, Work Week Manager
J. Powers, Engineering Director
P. Roberts, Maintenance Manager
M. Roder, Operations Manager
J. Rogers, Plant Engineering Manager
R. Slyker, Licensing Staff Engineer
H. Stevens, Quality Assurance Manager
G. Wolf, Licensing Staff Engineer

Nuclear Regulatory Commission

J. Grobe, Chairman, Davis-Besse Oversight Panel
C. Lipa, Chief, Reactor Projects Branch 4
S. Thomas, Senior Resident Inspector

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-346/02-14-01a	NCV	Lack of a design basis analysis for containment isolation valve backup air supplies
50-346/02-14-01b	NCV	Inadequate blowdown provisions for CAC backup air accumulators
50-346/02-14-01c	URI	Failure to perform comprehensive Moderate Energy Line Break analysis
50-346/02-14-01d	URI	Lifting of Service Water Relief Valves
50-346/02-14-01e	URI	Inadequate SW pump room temperature analysis
50-346/02-14-01f	URI	Inadequate SW pump room steam line break analysis
50-346/02-14-01g	URI	Inadequate cable ampacity analysis
50-346/02-14-01h	URI	Inadequate flooding protection for the SW pump house
50-346/02-14-01i	NCV	Non-conservative TS value for 90 percent undervoltage relays

50-346/02-14-01j	URI	Poor quality calculation for 90 percent undervoltage relays
50-346/02-14-01k	NCV	Non-conservative relay setpoint calculation for the 59 percent undervoltage relays
50-346/02-14-01l	URI	Inadequate calculations for control room operator dose (GDC-19) and offsite dose (10 CFR Part 100) related to HPI pump minimum flow valves
50-346/02-14-01m	URI	Other GDC-19 and 10 CFR Part 100 issues
50-346/02-14-01n	URI	HPI Pump Operation Under Long Term Minimum Flow
50-346/02-14-01o	URI	Some small break LOCA sizes not analyzed
50-346/02-14-01p	URI	Inadequate SW flow analysis
50-346/02-14-01q	URI	Inadequate SW thermal analysis
50-346/02-14-01r	URI	Inadequate UHS inventory analysis
50-346/02-14-01s	URI	No Valid Service Water Pump Net Positive Suction Head Analysis
50-346/02-14-01t	URI	SW source temperature analysis for AFW
50-346/02-14-01u	URI	Inadequate short circuit calculations
50-346/02-14-01v	NCV	No analytical basis for the setpoint to swap service water system discharge path
50-346/02-14-02a	NCV	SW surveillance test did not use worst case values
50-346/02-14-02b	URI	Inadequate SW system flow balance testing
50-346/02-14-03a	URI	Inappropriate SW pump curve allowable degradation
50-346/02-14-03b	URI	Repetitive failures of SW relief valves
50-346/02-14-03c	URI	Non-Conservative Difference in UHS Temperature Measurements
50-346/02-14-03d	NCV	Inadequate corrective actions related to SW pump discharge check valve acceptance criteria
50-346/02-14-03e	URI	Non-conservative containment air cooler mechanical stress analysis

50-346/02-14-04	NCV	Failure to perform TS surveillance requirement for HPI pump following maintenance
50-346/02-14-05	URI	Question regarding the definition of a passive failure
50-346/02-14-06	URI	Question regarding licensee compliance with code relief valve requirements

Closed

None

Discussed

None

LIST OF ACRONYMS USED

AC	Alternating Current
ASME	American Society of Mechanical Engineers
AFW	Auxiliary Feedwater
B&W	Babcock and Wilcox
BWST	Borated Water Storage Tank
CAC	Containment Air Cooler
CFR	Code of Federal Regulations
CR	Condition Report
CST	Condensate Storage Tank
CTMU	Cooling Tower Makeup
DHR	Decay Heat Removal
ECCS	Emergency Core Cooling System
GDC	General Design Criteria
GL	Generic Letter
gpm	Gallon Per Minute
HPI	High Pressure Injection
LER	Licensee Event Report
LIR	Latent Issues Review
LOCA	Loss of Coolant Accident
LOOP	Loss of Off-Site Power
LPI	Low Pressure Injection
MCC	Motor Control Center
MELB	Moderate Energy Line Break
M&TE	Measurement and Testing Instrumentation
MOV	Motor Operated Valve
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
PCAQR	Potential Conditions Adverse to Quality Report
PDR	Public Document Room
psig	pounds per square inch gage
PT	Potential Transformer
RCS	Reactor Coolant System
RPV	Reactor Pressure Vessel
SBLOCA	Small Break Loss of Coolant Accident
SDP	Significance Determination Process
SSCs	Systems, Structures and Components
SSDPC	Safety System Design and Performance Capability
SFP	Spent Fuel Pool
SW	Service Water
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
URI	Unresolved Item
USNRC	United States Nuclear Regulatory Commission
VAC	Volts Alternating Current
VDC	Volts Direct Current

LIST OF DOCUMENTS REVIEWED

The following is a list of licensee documents reviewed during the inspection, including documents prepared by others for the licensee. Inclusion on this list does not imply that NRC inspectors reviewed the documents in their entirety, but that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion on this list does not imply NRC acceptance of the document, unless specifically stated in the inspection report.

Calculations

C-EE-003.02-012	Protective Relay Setpoint for Transformer BD (Bkr HBBD)	Revision 2
C-EE-004.01-001	Protective Relay Setpoint for Service Water Pump Motor 1-1 (AC107)	Revision 4
C-EE-004.01-002	Protective Relay Setpoint for Service Water Pump Motor 1-2 (AD107)	Revision 4
C-EE-004.01-003	Protective Relay Setpoint for Service Water Pump Motor 1-3 (AC 109)	Revision 2
C-EE-004.01-004	Protective Relay Setpoint for Service Water Pump Motor 1-3 (AD109)	Revision 2
C-EE-004.01-009	Protective Relay Setpoint Calculation for High Pressure Injection Pump Motor 1-1 (AC111)	Revision 2
C-EE-004.01-010	Protective Relay Setpoint Calculation for High Pressure Injection Pump Motor 1-2 (AD111)	Revision 1
C-EE-004.01-030	Protective Relay Setpoint Calculation for 4.16 kV Feeder Ground Relays	Revision 3
C-EE-004.01-031	Protective Relay Setpoint Calculation for Ground Fault Protection - 4.16 kV Buses C1 & C2	Revision 3
C-EE-004.01-032	Protective Relay Setpoint for Incoming to Transformer DF1-1 (Bkr AD1DF11)	Revision 2
C-EE-004.01-033	Protective Relay Setpoint for Incoming to Transformer DF1-2 (Bkr AD1DF12)	Revision 4
C-EE-004.01-038	Protective Relay Setpoint Calculation for Incoming Transformer CE1-1	Revision 4
C-EE-004.01-039	Protective Relay Setpoint Calculation for Incoming to Transformer CE1-2 (Bkr AC1CE12)	Revision 2
C-EE-004.01-043	Protective Relay Setpoints for Ground Fault Protection - 4.16 kV Buses D1 & D2	Revision 3

C-EE-004.01-046	4.16 kV Short Circuit Calculations	July 8, 1991
C-EE-004.01-047	Protective Relay Setpoint Calculation for Phase Fault Protection - 4.16 kV Buses C1 & C2	Revision 2
C-EE-004.01-048	Protective Relay Setpoint Calculation for Phase Fault Protection - 4.16 kV Buses D1 & D2	Revision 3
C-EE-004.01-049	4.16 Kv Bus Degraded Voltage (90 percent Undervoltage) Relay Setpoint	November 7, 2001
C-EE-004.01-050	4.16 kV Bus Motor Residual Voltage Calculation	Revision 0
C-EE-004.01-051	59 percent Undervoltage (Loss of Station Power) Setpoint Calculation	Revision 3
C-EE-004.01-055	Motor Damage Data Extrapolation for Schulz HPI Pump Motor	Revision 0
C-EE-006.01-026	Voltage Drop for GL 89-10 Valve Operators	November 9, 1992
C-EE-015.03-003	Steady State Analysis - Electrical Load Management System ELMS	Revision 23
C-EE-015.7-001	Power Cable Ampacity	May 7, 1992
Calculation No. 24.001	Calculate Temperature -vs- Time for Loss of Ventilation in Room 323, 324, and 325	Revision 1
C-NSA-011.01-003	Allowable Service Water Flow Diversion During Cold Weather	Revision 1
C-NSA-016.04-007	Allowed CCW System Essential Header Integrated Leakage	Revision 0
67.005	Service Water Pump Room Ventilation System Capacity	Revision 2
67.004	Service Water Pump Maximum Allowable Outside Air Temperature to Dissipate Entire Room Heat Load with One Ventilation Fan C99 1, 2, 3, or 4 Operable	Revision 1
Calculation C-NSA-032.02-003	Maximum Allowable Service Water Temperature w/ Inoperable ECCS Room Cooler	Revision 4
Calculation C-NSA-52.01-003	HPI Pump Acceptance Criteria	Revision 4
Calculation C-NSA-52.01-012	Maximum Allowable Leak Rate through HP31/32 or ECCS Systems	Revision 0

Calculation 25.006	ECCS Rooms - Cooling System	Revision 1
Calculation 35.25	Dose Rate from BWST	Revision 0
Calculation 36.28	ECCS - Pump Seal Failure	Revision 0
C-NSA-011.01-004	Service Water Pump Startup/Coastdown Time for CAC Water Hammer Input	Revision 0
C-NSA-011.01-008	Replacement of SW1356, SW1357 and SW1358	Revision 0
SAROS/92-02	Identification of Flood Initiating Events for the Davis-Besse Individual Plant Examination	
C-NSA-011.01-007	Service Water Discharge Through SW 2929	February 6, 2001
C-CSS-011.01-170	Service Water Return Line to Forebay from SW 2929	December 19, 2000
C-NSA-085.00-002	Auxiliary Steam Blowdown in the Intake Structure	October 30, 1993
12501-M-001	UHS Thermal Performance for Pond Water Area and Volume to Station 10+00	July 14, 1998
H&H-1	Thermal Performance Analysis for Ultimate Heat Sink (UHS) Pond	December 26, 1995
NOPS 99-464	UHS Silting Study	October 20, 1999
C-NSA 011.01-010	Maximum Service Water Pressure to AFW System	April 2, 2002
C-NSA-60.05-008	Containment Post LOCA Response with Variable SW Temperature	October 20, 2001
C-NSA-000.00-017	PROTO-FLO Service Water System Model	December 19, 2001
C-NSA-011.01-003	Allowable Service Water Flow Diversion During Cold Weather	March 21, 1997
C-CSS-011.01-172	Seismic Evaluation For Control Appurtenances On Valves SW 1356, SW 1357, and SW 1358	
C-ICE-011-01-001	Service Water Pump Discharge Pressure Switches	September 2, 1986
C-NSA-60.05-007	CAC Heat Duty At Elevated SW Inlet Temperatures	August 10, 1998
12501-M-003	ECCS Room Temperatures with Initial 90F Forebay	May 27, 1999

67.005	Service Water Pump Room Ventilation System Capacity	August 30, 2002
67.007	Service Water Pump Room Ventilation System - Pressure Drop	August 30, 2002
C-CSS-11.01-169	Containment Air Cooler Evaluation For Generic Letter 96-06	October 1, 1997
C-CSS-011.01-171	Structural Analysis of Service Water Strainer Internals	November 30, 2000
12501-M-00004	UHS Pond Performance Analysis - Max Evaporation - Silt	March 15, 2001

Condition Reports Reviewed

CR 02-02658	Inadequate Ventilation for Rooms 323, 324, 325	June 18, 2002
CR 02-06120	SHRR - Testing Review - Maintenance Burden Associated with Undervoltage Relays	September 18, 2002
CR 02-06243	SSDPC Issue - Calculation Approved Prior to Receipt of LAR	September 19, 2002
CR 02-06428	SSDPC - Review of Calculation C-EE-004.01-051, 59 percent Undervoltage, Revision 3	September 22, 2002
CR 02-06430	SSDPC - Review of Calculation C-EE-004.01-049, Revision 10, 90 percent Degraded Voltage	September 21, 2002
CR 2000-2428	No title	October 9, 2000
CR 01-0005	SW2930 Stroke Time Increase	January 1, 2001
CR 01-0053	Screenwash to Circ. Water Pump Chlorine Diffuser Pipe Rupture	January 8, 2001
CR 01-0059	Water Treatment Building Sump Pumps Removed	January 9, 2001
CR 01-0340	Degrading Trend of Service Water Butterfly Manual Isolation Valves	February 5, 2001
CR 01-0350	Inadequate Design of Service Water Header Relief Valves	February 5, 2001
CR 01-0429	Service Water Pump 1 has Rain Water Leaking on Its Motor	February 14, 2001

CR 01-0459	HPI Pump 1 D/P Trending Down	February 16, 2001
CR 01-0512	Traveling Screen #3- Failed to Start	February 21, 2001
CR 01-0676	Tubing Configuration on Instrumentation	March 8, 2001
CR 01-0679	SW 2945 Bent Position Indicator	March 8, 2001
CR 01-0842	DB-SC-4146, Quarterly Functional of RE8434 Failed Low Flow Alarm Function	March 24, 2001
CR 01-0871	HPI 2 AC Oil Pump Motor Bearing Degradation	March 17, 2001
CR 01-0934	Missing P111-B Fastener	April 2, 2001
CR 01-1002	Unexpected Service Water Motor Temperature Increase	April 9, 2001
CR 01-1267	ECCS Cooler Operability Justification	May 14, 2001
CR 01-1716	Lack of Service Water Chlorination	July 10, 2001
CR 01-1724	Service Water Pump 3 Test Data Problems	July 10, 2001
CR 01-1787	M&TE Accuracies in Six I&C Data Packages Outside Calculation Allowed Accuracies	July 18, 2001
CR 01-1788	M&TE Used in Two Calibrations Did not Meet Applicable Accuracy Requirements	July 18, 2001
CR 01-1789	Design Database Errors for Service Water Pump Discharge Pressure Switches	July 18, 2001
CR 01-2532	Testing of Service Water Pump Cables	September 26, 2001
CR 01-2763	P58-1 & P58-2 Bolting Non-Compliance with ASME Code	October 18, 2001
CR 01-3115	HPI Recirc Flow	November 20, 2001
CR 01-3261	Service Water Pump 1 Motor Identified Problems	December 6, 2001
CR 01-3292	SW-1356 Closing Stroke Time Increase	December 10, 2001
CR 02-00754	Scheduling Conflict on HPI Pumps 1 and 2	February 23, 2002

CR 02-00899	Improvements Required in DB-OP-06904	February 25, 2002
CR 02-01058	Mod 99-0039 Calc Basis Determination Concerns	March 5, 2002
CR 02-01419	Chlorination of the Service Water System	March 29, 2002
CR 02-01450	Modification 99-0039 Does not Adequately Address New Valve Design	April 3, 2002
CR 02-01589	Some Floor Drains on East Side of CTMT 565’ Level are Plugged	April 18, 2002
CR 02-01848	Inspection Plan IP-M-029 Extent of Condition Area 565-3P	May 2, 2002
CR 02-01937	Inspection Plan IP-M-029 Containment Area Inspection Findings	May 6, 2002
CR 02-01998	Inspection Plan IP-M-029 Area 565-1P, Room 216-East D-ring, Interior Findings	May 13, 2002
CR 02-02016	Pipe Support 33A-HCB-2-H13 Removal/Reinstallation	May 13, 2002
CR 02-02038	Inspection Plan IP-M-028 Findings Component HP57	May 14, 2002
CR 02-02040	Inspection Plan IP-M-028 Findings Component HP56	May 14, 2002
CR 02-02041	Inspection Plan IP-M-028 Findings Component HP48	May 14, 2002
CR 02-02056	Post Loca Boron Precipitation Design Issues	May 15, 2002
CR 02-02088	Inspection Plan IP-M-029 Area 585-5E Findings	May 15, 2002
CR 02-02294	Degradation of Containment Air Cooler #1 Due to Boric Acid Corrosion	May 28, 2002
CR 02-02391	Intake Chlorine Pump Will Not Maintain Its Prime	June 2, 2002
CR 02-02394	Degradation of Service Water Piping in Containment	June 3, 2002
CR 02-02432	SW Pump 3 Flowrate Limited by Strainer Blowdown	June 5, 2002
CR 02-02478	PR/PSA: Improvements in the CCW System Need to be Considered	June 7, 2002
CR 02-02749	Boric Acid on Equipment in the Aux Building	June 24, 2002
CR 02-02764	Service Water Piping Inside Containment Unqualified Paint	June 24, 2002
CR 02-02943	Containment Air Cooler Boric Acid Corrosion	July 2, 2002

CR 02-03028	HPI Stop Check Valves May Not be Oriented Correctly	July 8, 2002
CR 02-03224	Boric Acid on HP4BB Due to Body to Bonnet Leak	July 15, 2002
CR 02-03235	SW1434 Did Not Respond as Expected During Post Maintenance Testing	July 15, 2002
CR 02-03256	Degradation of Circulation Water Chlorination Supply Lines	July 16, 2002
CR 02-03383	Problems with HP 48	July 22, 2002
CR 02-03655	High Pressure Injection Boron Corrosion	August 8, 2002
CR 02-03972	Degradation of Service Water Supply Piping to Auxiliary Feed Water Pumps	August 10, 2002
CR 02-04173	SHRR Walkdown of HPI Train 1, Corrosion Issues	August 10, 2002
CR 02-04419	Biofouling of Containment Air Cooler E37-3	August 16, 2002
CR 02-04697	MCC Bucket for BF1281	August 21, 2002
CR 02-04760	BF 1281 Loose Terminal	August 21, 2002
CR 02-05011	SHRR Walkdown of HPI Train 2: Insulation Issues	August 16, 2002
CR 02-05528	LIR-SW:ECCS Room Cooler Material Deficiencies	August 14, 2002
CR 02-05563	Nozzle Flexibility Assumed in Calculation 65A/B (Part II) is Non-Conservative	September 5, 2002
CR 00-1779	No test to verify flow from Service Water System to Component Cooling Water System for Makeup	July 13, 2000
CR 01-2928	Intake Structure Flooding Issue with Pumps Removed	November 1, 2001
CR 02-04514	Inadequate Interface Between the IST Program and Design Basis Information	August 19, 2002
CR 02-05784	Service Water Strainer Design Flow	
CR 02-06370	SSDPC: ECCS Pump Room Heat Load Calculation is Non-conservative	September 20, 2002
CR 02-06388	SSDPC: Issues with DB-OP-06261 Guidance for Inoperable ECCS Room Coolers	September 20, 2002

CR 02-07232	LIR CCW - Non-conservative CCW Leakage Calculation	October 2, 2002
CR 02-07378	LIR CCW - Service Water to CCW Makeup Line Flow Verification Test Discrepancies	October 3, 2002
CR 00-0096	Failure to Perform Off-site AC Sources Line Up as Required by Tech Spec	January 17, 2000
CR 00-4035	Closing Springs Failed to Charge	December 18, 2000
CR 00-4113	ACD2 Would Not Close When Placing #3 CCW in Service As 1	December 24, 2000
CR 00-4116	ACD3 Breaker Closed When the Springs Discharged While Racking Out	December 24, 2000
CR 01-0043	Maintenance Rule (a)(1) Corrective Action Plan for Breakers may Need Re-evaluating	February 4, 2001
CR 01-0138	Some Inhouse Refurb Breakers Have Different Stock Code Arcing Contact Mt	January 2, 2001
CR 01-0413	Circuit Breaker ACD3 Did Not Pass Post-Maintenance Checks	February 12, 2001
CR 01-0823	AC113 Failed Resistance Checks per Standing Order 99-09	March 22, 2001
CR 01-1049	Breaker Could Not Be Tested per DB-OP-01000	April 21, 2001
CR 01-1104	C1 Low Voltage Alarms	April 22, 2001
CR 01-1721	DC Bus 1 Ground	July 10, 2001
CR 01-2120	AC113 Thermography Noted Warm Relay Not Noted in Other Breakers	August 16, 2001
CR 01-2158	High Voltage Switchgear Room Temperature Concerns	August 21, 2001
CR 02-00817	Inadequate Clearance on AD 111 Trip Plunger	February 26, 2002
CR 02-01161	59 percent UV Relay Failure	May 9, 2002
CR 02-01526	Unexpected AC Transformer Lockout	April 11, 2002
CR 02-01550	Unexpected AC Transformer Lockout	April 15, 2002
CR 02-02658	Inadequate Ventilation for Rooms 323, 324, 325	June 18, 2002
CR 02-03845	Loose Termination in AC 113	August 8, 2002

CR 02-04999	SHRR - Testing Review for 4.16 kV System	August 26, 2002
CR 02-05000	SHRR - Testing Review for 4.16 kV System	August 26, 2002
CR 02-03331	Noteworthy Items from Test Control Program Self Assessment	July 19, 2002
CR 02-04514	Inadequate Interface Between the IST Program and Design Basis Information	August 19, 2002
CR 02-05369	LIR of Inadequate Service Water System Flow Balance Procedure	September 2, 2002
CR 00-2478	Service Water Relief Valves Lifted and Failed to Reseat	October 13, 2000
CR 01-2182	Bench Testing SW 3963 Relief Valve During 13RFO	August 23, 2001
CR 01-2407	#1 Service Water Pump Strainer Leak	September 18, 2001
CR 01-0350	Inadequate Design Of Service Water Header Relief Valves	February 5, 2001
CR 02-04514	Inadequate Interface Between The IST Program And Design Basis Information	August 19, 2002
CR 02-05372	LIR of Service Water System Design Flow Rates to the ECCS Room Coolers	September 2, 2002
CR 02-05640	No Design Basis/Flow verification Testing of SW Flow to AFW System	September 7, 2002
CR 02-05923	No Design Basis For Service Water Pump NPSH Available	September 13, 2002
CR 02-05966	LIR-SW-EQ Walkdown	August 30, 2002
CR 02-06139	SSDPC Self Assessment Identified Seismic II/I Concern for CTMU Pumps	September 18, 2002
CR 02-06177	CREVS Calculation Not Updated To Address 90F Temperature Increase	September 18, 2002
CR 02-06297	Cooling Tower Makeup and Service Water Pumps	September 19, 2002
CR 02-06436	Collective Significance of Issues From SW Self Assessment and LIR	September 21, 2002

CR 02-06438	Evaluate Worst Case (Highest Flow) for the Service Water System	September 21, 2002
CR 02-06546	Design Basis Validation Open Items - Containment Air Coolers	September 23, 2002
CR 02-06791	ECCS Room Cooler Common Outlet Isolation Valve	September 26, 2002
CR 02-07004	Heat Added by SW Pumps Not Accounted For In Containment Response Analysis	September 29, 2002

Condition Reports Written As a Result of Inspection

CR 02-06571	Calculation Inadequacy	September 24, 2002
CR 02-06737	SSDPC - Calc C-EE-004.01-051 Uncertainty Treatment	September 25, 2002
CR 02-06837	Inadequate Supervisor’s Review of CR 02-06302	September 27, 2002
CR 02-06893	Unevaluated Temperature Increase Because of LAR 96-008	September 24, 2002
CR 02-07633	SSDPC/Uncertainties Treatment in C-EE-004.01-049 R10 Is Non-Conservative	October 8, 2002
CR 02-07646	SSDPC - Calc C-EE-004.01-051 Temperature Variation Not Considered	October 8, 2002
CR 02-07766	Non-Conservative Value for 90 percent Volt in Table 3.3-4	October 9, 2002
CR 02-06618	Appendix R Disconnect Switch Cabinet Found Open During NRC Walkdown	September 24, 2002
CR 02-06674	HP 209 Was Found Out of Expected Position	September 24, 2002
CR 02-06726	Leakage Collection Devices and Their Usage in RRA Clarification	September 25, 2002
CR 02-06749	NRC Inspection of Top of BWST Tank	September 26, 2002
CR 02-06750	NRC Walkdown of the BWST	September 26, 2002

CR 02-06571	Calculation Inadequacy	September 24, 2002
CR 02-06855	NRC Walkdown of HPI in Containment	September 27, 2002
CR 02-06801	Corrosion in Room 115	September 26, 2002
CR 02-07611	NRC Walkdown of HPI	October 7, 2002
CR 02-07643	Improvements to DB-OP-02003, For HPI Flow Alarm Response	October 8, 2002
CR 02-07753	Failure to Require TS 4.5.2.H HPI Flow Testing Following Maintenance	September 9, 2002
CR 02-07779	Cable Seal for CCW Rad Monitor	September 24, 2002
CR 02-07791	NRC Question On HPI System Modifications	October 10, 2002
CR 02-07475	Instrument Inaccuracy for Air Temperature Not Considered in Service Water Ventilation Calculation	October 4, 2002
CR 02-07657	Service Water Pump Design Flow Rate in Question	October 8, 2002
CR 02-07762	Questions on Mounting for CCW Heat Exchangers	October 9, 2002
CR 02-07764	Calculation/Test May Not Consider Actual Plant Conditions	October 9, 2002
CR 02-07770	Security Equipment	October 9, 2002
CR 02-07802	Calculational Basis for PSH 2929 and PSH 2930 setpoint could not be found	October 10, 2002
CR 02-07820	Bent Anchor Bolt on the CCW Ht Exchanger #1 Sliding Connection	October 10, 2002
CR 02-06615	Work Area in MPR #1 Unsatisfactory	September 24, 2002
CR 02-06701	Post Loca Dose from BWST with Inadvertent HP31/HP32 Failure	September 25, 2002
CR 02-06702	Potential for Inadequate HPI Pump Minimum Recirculation Following LOCA	September 25, 2002

CR 02-06571	Calculation Inadequacy	September 24, 2002
CR 02-06863	Extent of Condition of CR 02-05369	September 26, 2002
CR 02-06996	HPI Flow Test Acceptance Criteria Versus T.S. 4.5.2.h	September 28, 2002
CR 02-07338	High Pressure Injection System Description (SD-038)	October 2, 2002
CR 02-07466	HPI Pumps Test Procedures Deficiency with Required Test Instrumentation Accuracy	October 4, 2002
CR 02-07468	SSDP: Unverified Calculations in SW Qtrly Tests DB-PF-03017, -03023, -03030	October 4, 2002
CR 02-07684	HPI Pump Capability to Run at Minimum Flow	October 8, 2002
CR 02-07701	Control Room Operator Dose Due to ECCS Leakage Post-LOCA	October 9, 2002
CR 02-07713	Post Accident Control Room Dose Calculations	October 9, 2002
CR 02-07741	Acceptance Criteria of ECCS Sump Test below USAR Assumption	October 9, 2002
CR 02-07757	Environmental Conditions for Decay Heat Pump Seal Leak Not Evaluated	October 4, 2002
CR 02-07777	DHR System Needs Critical Crack Evaluation	October 9, 2002
CR 02-07781	Weaknesses in Testing SW Outlet Valves to CAC Coolers (SW - 1356, 1357, 1358)	October 9, 2002
CR 02-05986	UHS Water Inventory Analysis Does Not Consider All Water Losses	September 14, 2002
CR 02-06064	SW Flow Balance Margins and Need For Additional Recorded Data	September 15, 2002
CR 02-06332	Potential Weaknesses Service Water Single Failure Analysis	September 20, 2002
CR 02-06333	Concerns With Calculation C-NSA-011.01-001	September 20, 2002
CR 02-06336	UHS Analyses Do Not Document That Worst-Case Conditions are Enveloped	September 20, 1992

CR 02-06571	Calculation Inadequacy	September 24, 2002
CR 02-06344	Design Basis Concerns Regarding Service Water Strainer Backwash Function	September 20, 2002
CR 02-06370	ECCS Pump Room Heat Load Calculation Is Non-Conservative	September 20, 2002
CR 02-06379	ECCS Pump Room Heat Load Calculation Is Non-Conservative	September 20, 2002
CR 02-06860	Review of the Need for Relief Valves for Several Heat Exchangers	September 27, 2002
CR 02-07188	Non-Conservative Assumptions in Calc 76.005, SW Ventilation Capacity	October 2, 2002
CR 02-07286	Enhance RA-EP-02880, Internal Flooding Procedure	October 2, 2002
CR 02-07569	Station Sump Pump Check Valves Not Tested	October 7, 2002
CR 02-07427	Drainage Systems - Aux Building Dwg —173, Note 8 Requires Clarification	October 4, 2002
CR 02-07692	USAR Section 9.2.5.1 Concerning Placing SWP(s) Into Operation After 13 Hours	October 8, 2002
CR 02-07714	Lack of Procedures to Isolate SWP Room Equipment During Flooding	October 8, 2002
CR 02-07716	Wrong instrument May Be Used To Verify Ultimate Heat Sink Temperature	October 9, 2002
CR 02-07745	No Allowance for Flow Diversion in Calc C-NSA-00.00-17	October 9, 2002
CR 02-07746	Building Drainage Failure Criteria Question	October 9, 2002
CR 02-07750	Basis For Air Operated Containment Isolation Valve Air Volume Tanks	October 9, 2002
CR 02-07752	NRC Inspection of SW, Transient Spikes in CTMT SW Pressure Lines	October 9, 2002
CR 02-07760	Flood Analysis Discrepancies in the Service Water Pipe Tunnel and Valve Rooms	October 9, 2002
CR 02-06108	AFW Pumps and H2 Dilution Blower Not Evaluated for Maximum SW Temperature	September 17, 2002

CR 02-06571	Calculation Inadequacy	September 24, 2002
CR 02-07781	Weaknesses In Testing SW Outlet Valves to CAC Coolers	October 9, 2002

Drawings

E-1 SH. 1, 2, 3	AC Electrical System One Line Diagrams	Revisions 21, 31, 2
E-3	4.16 kV Metering and Relaying One Line Diagram	Revision 30
E-39 B SH. 11	Misc Control Schemes - Medium Voltage SWGR Rooms Lighting	Revision 3
E-52B SH. 63	HPI Pump AC Lube Oil Pump	Revision 3
E-52B SH. 64	HPI Pump DC Lube Oil Pump	Revision 5
DWG —033A	High Pressure Injection	Revision 3
DWG 041A	Service Water Pumps and Secondary Service Water	Revision 23
DWG 041B	Service Water Pumps and Secondary Service Water	Revision 54
DWG 041C	Service Water Pumps and Secondary Service Water	Revision 25
DWG OS-020	Operational Schematic Service Water System	Revision 55
DWG —030A	Reactor Coolant System	Revision 52
DWG —363	Sprinkler System SW Pump Rm 52 Intake Structure Elev. 576'-0"	Revision 2
Operational Schematic OS-003	High Pressure Injection System	Revision 19
P&ID M-033A	High Pressure Injection	Revision 30
Goulds Pumps Drawing Q307249	Backup Service Water Pump,	October 6, 1981
Goulds Pumps Drawing N300214401	Service Water Pumps	September 18, 1992
Goulds Pumps Drawing 301231	Dilution Pump P180	November 1, 1973
Goulds Pumps Drawing D-1375	Dilution Pump	August 9, 1973

P&ID M-041A	Service Water Pumps and Secondary Service Water System	Revision 23
P&ID M-041B	Primary Service Water System	Revision 54
P&ID M-041C	Service Water System for Containment Air Coolers	Revision 25
P&ID M-006D	Auxiliary Feedwater System	Revision 47
Piping System Composite M-251F	Intake Structure	Revision 17
Goulds Pumps Drawing T74-082	Service Water Pump P3-1 Pump Curves	March 15, 1974
Goulds Pumps Drawing T74-084	Service Water Pump P3-2 Pump Curves	March 15, 1974
Goulds Pumps Drawing T74-090	Service Water Pump P3-3 Pump Curves	March 2, 1974
C-1595	Penetration Schedule	Revision 7
Equipment Locations Dwg —135	Intake Structure & Water Treatment Building Plans	Revision 29
M-473-A	Low Density Silicone Foam Penetration Seal Typical Details	Revision 1
M-473-B	High Density Silicone Elastomer Penetration Seal Typical Details	Revision 0
M-473-C	Grout or Ceramic Fiber and Caulk Penetration Seal Typical Details	Revision 1
A-2110	Barrier Penetration Drawing Barrier Identification Plan Rm 52 Intake Structure Elev. 576'-0"	Revision 0
A-2112	Barrier Penetration Drawing Barrier Identification Plan Rm 53 Intake Structure Elev. 566'-0"	Revision 1
A-2111	Barrier Penetration Drawing Barrier Identification Plan Rm 52-E Intake Structure	Revision 0
C-1594	Barrier Functional List	Revision 2

Procedures

DB-OP-02001	Electrical Distribution Alarm Panel 1 Alarm Procedure	Revision 3

DB-OP-02103	Transformer AC Alarm Panel 103 Annunciators	Revision 1
DB-OP-02104	Transformer BD Alarm Panel 104 Annunciators	Revision 1
DB-OP-02521	Loss of AC Bus Power Sources	Revision 2
DB-OP-06315	4160 Volt Switching Procedure	Revision 2
DB-OP-06316	Diesel Generator Operating Procedure	Revision 2
DB-OP-06334	Station Blackout Diesel Generator Operating Procedure	Revision 3
DB-OP-06904	Shutdown Operations	Revision 6
DB-OP-02000	RPS, SFAS, SFRCS Trip, or SG Tube Rupture	Revision 6
DB-OP-00008	Operation and Control of Locked Valves	Revision 1
DB-OP-02511	Loss of Service Water Pumps/Systems	Revision 2
DB-OP-03007	Miscellaneous Instruments Daily Check	Revision 3
DB-OP-06016	Containment Air Cooling System Procedure	Revision 4
DB-OP-06261	Service Water System Operating Procedure	Revision 2
DB-OP-06262	Component Cooling Water System Operating Procedure	Revision 2
DB-OP-06904	Shutdown Operations	Revision 6
DB-OP-06913	Seasonal Plant Preparation Checklist	Revision 4
DB-MM-03006	Inspection of Tech Spec Hydraulic Snubbers	Revision 1
DB-PF-03017	Service Water Pump 1 Quarterly Test	Revision 2
DB-PF-03020	Service Water Train 1 Quarterly Valve Test	Revision 4
DB-PF-03023	Service Water Pump 2 Quarterly Test	Revision 2
DB-PF-03026	Service Water Manual Valve Test	Revision 0
DB-PF-03027	Service Water Train 2 Quarterly Valve Test	Revision 4
DB-PF-03100	Component Cooling Water Valve Test	Revision 4
DB-PF-03154	AFW Train 1 Valve Testing	Revision 4
DB-PF-03163	AFW Train 2 Valve Testing	Revision 4
DB-PF-03205	ECCS Train 1 Valve Test	Revision 4
DB-PF-03206	ECCS Train 2 Valve Test	Revision 3
DB-PF-03811	Miscellaneous Valves Test	Revision 6

DB-PF-03812	Miscellaneous Valves Cold Shutdown and Refueling Test	Revision 6
DB-PF-03813	Miscellaneous Augmented Valve Test	Revision 0
DB-PF-04704	Performance Test - Component Cooling Water Heat Exchanger 1	Revision 4
DB-PF-04705	Performance Test - Component Cooling Water Heat Exchanger 2	Revision 3
DB-PF-04706	Performance Test - Component Cooling Water Heat Exchanger 3	Revision 3
DB-PF-04729	Containment Air Cooler Monitoring Test	Revision 6
DB-PF-04736	ECCS Room Cooler Monitoring Test	Revision 0
DB-SC-03114	SFAS Integrated Time Response Test	Revision 1
DB-SC-03122	SFAS Components Test	Revision 1
DB-SP-03018	Service Water Pump 1 Refueling Test	Revision 2
DB-SP-03019	Service Water Valve Verification Monthly Test Train 1	Revision 1
DB-SP-03024	Service Water Pump 2 Refueling Test	Revision 2
DB-SP-03026	Service Water Valve Verification Monthly Test Train 2	Revision 1
DB-SP-03032	Service Water Pump 3 Refueling Test	Revision 2
DB-SS-03041	Control Room Emergency Ventilation System Train 1 Monthly Test	Revision 3
DB-SS-03042	Control Room Emergency Ventilation System Train 2 Monthly Test	Revision 3
DB-SS-04021	Backup Service Water Pump Quarterly Test	Revision 2
DB-SC-03020	13.8 KV System Bus A & B Transfer Test	Revision 3
DB-SC-03022	Off-site AC Sources Bus Transfer Test	Revision 2
DB-SC-03023	Off-site AC Sources Lined Up and Available	Revision 3
DB-SC-03041	On-site AC Bus Sources Lined Up, Available and Isolated (Modes 1, 2, 3, and 4)	Revision 2
DB-SC-03042	On-site AC Bus Sources Lined Up and Available (Modes 5 and 6)	Revision 2
DB-SC-04052	4160V System Transfer and Lockout Test - Buses D1 and D2	Revision 1

DB-SC-04053	4160V System Transfer and Lockout Test - Buses C1 and C2	Revision 1
DB-SC-10000	Main Transformer Backfeed Test	Revision 0
Emergency Procedure DB-OP-02000	RPS, SFAS, SFRCS Trip, OR SG Tube Rupture	Revision 06
Systems Procedure DB-SP-04162	ECCS Sump Pump Flow Check	Revision 01
Surveillance Test Procedure DB-PF-03011	ECCS Integrated Train 1 Leakage Rate Test	Revision 00
Surveillance Test Procedure DB-PF-03012	ECCS Integrated Train 2 Leakage Rate Test	Revision 00
Surveillance Test Procedure DB-PF-03017	Service Water Pump 1 Testing	Revision 03
Surveillance Test Procedure DB-SP-03218	HPI Train 1 Pump and Valve Test	Revision 04
Surveillance Test Procedure DB-SP-03219	HPI Train 2 Pump and Valve Test	Revision 05
Surveillance Test Procedure DB-PF-03020	Service Water Train 1 Valve Test	Revision 04
Surveillance Test Procedure DB-PF-03027	Service Water Train 2 Valve Test	Revision 04
Periodic Test Procedure DB-PF-04207	HPI Pump 1 Baseline Test	Revision 00
Mechanical Maintenance Procedure DB-MM-09266	Torquing	Revision4
RA-EP-02880	Internal Flooding	October 14, 1998

DB-OP-02011	Heat Sink Alarm Panel 11 Annunciators	September 16, 2002
DB-OP-06261	Service Water System Operating Procedure	June 6, 2002
DB-PF-03272	Post Maintenance Valve Test	Revision 2
DB-SP-03152	AFW Train 1 Level Control, Interlock and Flow Transmitter Test	Revision 6
DB-SP-03161	AFW Train 2 Level Control, Interlock and Flow Transmitter Tes	Revision 6
DB-OP-02000	Emergency Procedure Bases and Derivation Document	Revision 11
DB-OP-02000	Emergency Procedure	May 14, 2001
RA-EP-02830	Emergency Plan Off Normal Occurrence Procedure, Flooding	Revision 00

Surveillances and Tests

DB-MM-03006	Inspection of Tech Spec Hydraulic Snubbers	January 28, 2002
DB-PF-03017	Service Water Pump 1 Quarterly Test	February 8, 2000
	Service Water Pump 1 Quarterly Test	May 8, 2000
	Service Water Pump 1 Quarterly Test	September 8, 2000
	Service Water Pump 1 Quarterly Test	February 23, 2001
	Service Water Pump 1 Quarterly Test	April 29, 2001
	Service Water Pump 1 Quarterly Test	August 7, 2001
	Service Water Pump 1 Quarterly Test	October 30, 2001
	Service Water Pump 1 Quarterly Test	January 23, 2002
DB-PF-03020	Service Water Train 1 Quarterly Valve Test	January 26, 2000
	Service Water Train 1 Quarterly Valve Test	July 11, 2000
	Service Water Train 1 Quarterly Valve Test	March 7, 2001

	Service Water Train 1 Quarterly Valve Test	December 27, 2001
	Service Water Train 1 Quarterly Valve Test	January 23, 2002
DB-PF-03023	Service Water Pump 2 Quarterly Test	October 19, 2000
	Service Water Pump 2 Quarterly Test	January 8, 2001
	Service Water Pump 2 Quarterly Test	April 6, 2001
	Service Water Pump 2 Quarterly Test	June 29, 2001
	Service Water Pump 2 Quarterly Test	September 17, 2001
	Service Water Pump 2 Quarterly Test	November 11, 2001
DB-PF-03027	Service Water Train 2 Quarterly Valve Test	November 13, 2001
	Service Water Train 2 Quarterly Valve Test	December 11, 2001
	Service Water Train 2 Quarterly Valve Test	January 9, 2002
DB-PF-04704	Performance Test - Component Cooling Water Heat Exchanger 1	September 16, 1999
	Performance Test - Component Cooling Water Heat Exchanger 1	June 19, 2001
DB-PF-04705	Performance Test - Component Cooling Water Heat Exchanger 2	September 29, 1999
	Performance Test - Component Cooling Water Heat Exchanger 2	August 2, 2000
DB-PF-04706	Performance Test - Component Cooling Water Heat Exchanger 3	September 29, 1999
	Performance Test - Component Cooling Water Heat Exchanger 3	August 29, 2000
DB-PF-04729	Containment Air Cooler Monitoring Test	March 15, 1999
	Containment Air Cooler Monitoring Test	March 9, 2000

	Containment Air Cooler Monitoring Test	June 8, 2000
	Containment Air Cooler Monitoring Test	June 9, 2000
	Containment Air Cooler Monitoring Test	March 20, 2001
	Containment Air Cooler Monitoring Test	June 13, 2001
	Containment Air Cooler Monitoring Test	June 20, 2001
	Containment Air Cooler Monitoring Test	August 8, 2001
	Containment Air Cooler Monitoring Test	August 14, 2001
	Containment Air Cooler Monitoring Test	November 1, 2001
	Containment Air Cooler Monitoring Test	November 6, 2001
	Containment Air Cooler Monitoring Test	January 22, 2002
	Containment Air Cooler Monitoring Test	January 29, 2002
DB-PF-04736	ECCS Room Cooler Monitoring Test	July 21, 2000
	ECCS Room Cooler Monitoring Test	October 13, 2000
	ECCS Room Cooler Monitoring Test	April 11, 2001
	ECCS Room Cooler Monitoring Test	January 15, 2001
DB-SC-03114	SFAS Integrated Time Response Test	May 6, 1998
	SFAS Integrated Time Response Test	May 4, 2000
DB-SC-03122	SFAS Components Test	May 13, 1998
	SFAS Components Test	May 7, 2000
DB-SP-03032	Service Water Pump 3 Refueling Test	May 9, 2000
	Service Water Pump 3 Refueling Test	June 26, 2000
DB-SS-04021	Backup Service Water Pump Quarterly Test	April 18, 2002
	Backup Service Water Pump Quarterly Test	July 11, 2002

Other Documents

ISA-S67.04	Setpoints for Nuclear Safety-Related Instrumentation	September 1994
DB-ME-03045 R00	C1 Bus Undervoltage Units Monthly Functional Test	Revision 00
DB-ME-05319	GE NGV13B Voltage Relay Maintenance and Calibration	Revision 00
RFM 89-0011	Obsolete M-2 Valve Actuator	January 17, 1989
SCR 92-5013	Increase the Upper Bound of the Allowable Setpoint Range for the 59 percent Relays from 67 Volts to 69 Volts	June 16, 1992
FCR 83-063	Replace HPI Pump 1-2 AC Lube Oil Pump	May 2, 1983
Operability Justification 01-0015	Operability Justification 01-0015 for Condition Report 01-2158, High Voltage Switchgear Room Temperature Concerns	August 22, 2001
E-005-00154-4	Instr Man-I-T-E Single Phase Voltage Relays	35891
USAR Change Notice (UCN) 90-001	Safety Evaluations Associated with LAR 89-0017 and MOD 88-0234	January 8, 1990
Davis-Besse Letter - Serial No. 293	Response to NRC Regarding Davis-Besse Unit No. 1 Grid Stability	July 18, 1977
Davis-Besse Letter - Serial No. 1667	License Amendment Application to Clarify that Decay Heat Removal Valve DH23 Is not Subject to Type C Test Requirements (TAC Number 73244)	June 13, 1989
Davis-Besse Letter - Serial No. 1737	License Amendment Application to Remove Technical Specification Table 3.6-2, Containment Isolation Valves (TAC Number 75235)	December 22, 1989
Davis-Besse Letter - Serial No. 1794	Revision 11 to the Updated Safety Analysis Report	May 31, 1990
Davis-Besse Letter - Serial No. 1812	Withdrawal of License Amendment Applications to Revise Technical Specification 3/4.6.3.1, Containment Isolation Valves (TAC Numbers 66008 and 73244)	June 1, 1990
License Amendment No. 147	Amendment No. 147 to Facility Operating License No. NPF-3 (TAC No. 75235)	April 13, 1990

EPRI TR-103335	Guidelines for Instrument Calibration Extension/Reduction Programs	March 1994
DB-OP-02000	RPS, SFAS, SFRCS or SG Tube Rupture	Revision 06
	Basis and Deviation Document for DB-OP-02000	Revision 11
	Design Report for Modification 99-0039-00 Replace Valves SW 1356, SW 1357, and SW1358	Revision 0
Spec. 7749-M-319	Design Specification for Nuclear Ball and Butterfly Control Valves for The Toledo Edison Company and the Cleveland Electric Illuminating Company Davis-Besse Nuclear Power Station Unit No. 1	Revision 4
Spec. M-319CQ	Technical Specification for Operational Phase Service Water Nuclear Ball Control Valves SW 1356, SW 1357, and Sw 1358 for Davis-Besse Nuclear Power Station	Revision 0
SD-038	System Description for High Pressure Injection System	Revision 2
SD-003A	System Description for the 4160 volt Auxiliary System	Revision 3
SD-018	System Description for Service Water System	Revision 2
	High Pressure Injection Pump 1 Inservice Testing Data	October 8, 2002
	High Pressure Injection Pump 2 Inservice Testing Data	October 8, 2002
	High Pressure Injection Valve Inservice Testing Data	October 8, 2002
DB-OP-06011	High Pressure Injection System	Revision 02
DB-OP-02003	ECCS Alarm Panel 3 Annunciators	Revision 02
DB-PF-03205	ECCS Train 1 Valve Test	Revision 04
DB-OP-06331	Freeze Protection and Electrical Heat Trace	Revision 03
DB-PF-03207	HPI Pump Comprehensive and Check Valve Forward Flow Tests	Revision 02
EN-DP-01080	Calculations	Revision 01
DB-PF-03969	HPI System Pressure Isolation Integrity test Back-to Back Check Valves	Revision 04
DB-PF-03069	Check Valve reverse Flow Tests	Revision 04
Calc 67A	Pipe Stress Analysis	Revision 05

50-346/89-201	Interfacing System LOCA Inspection	December 22, 1989
50-346/92010	Announced Safety Inspection of the Licensee's Response to Generic Letter 89-10	August 20, 1992
SN 1793	Response to Inspection Report 50-346/89-201-Interfacing System Loss of Coolant Accident	April 27, 2002
UCN 98-022 U	Seismic Qualification of Valves SW-1424, SW-1429, and SW-1434	February 18, 2002
PCAQR 95-0681	T413 May Read Low	August 17, 1995
PCAQR 97-1174	Decay Heat Exchangers Overstressed	September 4, 1997
USAR 6.3	Emergency Core Cooling Systems	Revision 22
TS 3/4.5	Emergency Core Cooling Systems	
SD003A	System Description for the 4160 Volt Auxiliary System	Revision 3
Standing Order 02-005	Interim Guidance on High Voltage Switchgear Room Ventilation	July 13, 2002
	4160 VAC Maintenance Rule Scoping Documents	
	Davis-Besse Materiel Condition Report - Essential and Miscellaneous AC	4th Quarter 1999
	Davis-Besse Materiel Condition Report - Essential and Miscellaneous AC	2nd Quarter 2000
	Davis-Besse Materiel Condition Report - Essential and Miscellaneous AC	3rd Quarter 2000
	Davis-Besse Materiel Condition Report - Essential and Miscellaneous AC	4th Quarter 2000
	Davis-Besse Materiel Condition Report - Essential and Miscellaneous AC	1st Quarter 2001
	Davis-Besse Materiel Condition Report - Essential and Miscellaneous AC	2nd Quarter 2001
	Davis-Besse Materiel Condition Report - Essential and Miscellaneous AC	3rd Quarter 2001
	Davis-Besse Materiel Condition Report - Essential and Miscellaneous AC	4th Quarter 2001

	Davis-Besse Materiel Condition Report - Medium Voltage AC	1st Quarter 2002
	Davis-Besse Weekly Maintenance Risk Summary	February 12, 2002
M-45-18-4	Goulds Pumps Service Water Pumps Vendor Manual	October 30, 1987
MPR-876	Davis-Besse Auxiliary Feed Pumps Evaluation of Automatic Transfer of Suction to the Service Water System	October 1985
OS-020 SH 1	Service Water System Operational Schematic - Sheet 1	Revision 55
OS-020 SH 2	Service Water System Operational Schematic - Sheet 2	Revision 24
PFP-IS-52	Protected Area Pre-fire Plan for Service Water Pump Room, Room 52, Fire Area BF	Revision 2
SD-018	System Description for Service Water System	Revision 2
TM 02-0019	Temporary Modification - Install temporary flood barrier in place of Cooling Tower Makeup Pump #1	August 27, 2002
	Service Water Pump 1 IST Trend Data	September 2000 - present
	Service Water Valve Test Data	January 1992 - present
Letter Serial No. 1-904	Response to Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment	January 30, 1990
Letter Serial No. 1-966	Final Response to Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment	December 23, 1991
Letter Serial No. 1-1022	Supplemental Response to Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment	September 9, 1993
Letter Serial No. 2575	Commitment Change Summary Report	November 20, 1998
NRC Bulletin No. 88-04	Potential Safety Related Pump Loss	May 5, 1988
Toledo Edison Letter Serial No. 1-823	Subject: Response to NRC Bulletin No. 88-04: Potential Safety Related Pump Loss	September 8, 1988

Toledo Edison Letter Serial No. 1-871	Subject: Final Response to Nuclear Regulatory Commission (NRC) Bulletin No. 88-04: Potential Safety Related Pump Loss (TAC 69906)	April 14, 1989
Toledo Edison Letter Serial No. 1-849	Subject: Update on Activities Relating to NRC Bulletin No. 88-04: Potential Safety Related Pump Loss	December 16, 1988
Mod 94-0009	Service Water Thermal Relief Valve Replacement for Containment Air Coolers	April 1995
SCR 93-5016	Change PSL 1377, Service Water Strainer Discharge Pressure Switch to 55 PSIG	January 12, 1994
Mod 87-1076	Remove ECCS Room Coolers Service Water Return Check Valves' Internals	January 12, 1988
Mod 87-1290	Remove Internal of Valve SW-329	July 6, 1990
Mod 88-0234	Overpressure Protection for the Containment Air Coolers	November 11, 1988
FCR 84-0147	Service Water Pump Room Ventilation Upgrade	November 23, 1985
Mod 99-0039-00	CAC Temperature Control Valve Replacement	June 29, 1999
FCR 78-039	Change Setpoints on SW-PSH-2917 and SW-PSH-2917A	January 23, 1978
SE 87-0366	Remove Internals of Check Valves SW - 217 & SW - 218	January 12, 1988
SE 95-0056	Remove Relief Valves SW - 10210, SW - 10211, & SW -10212 From Containment Air Coolers	September 9, 1995
SE 84-147	Service Water Pump Room Ventilation Upgrade	November 23, 1985
SE 01-0008	CAC Temperature Control Valve Replacement	June 2, 2001

List of Documents Requested by USNRC

Document Request (Bob Daley)

Please provide a copy of the following documents (Items in Bold should be higher priority):

SCR 92-5028	Revise Setting 4.16 KV Bus	2/23/95
SCR 92-5029	Rev Trip Timer for 4.16 KV Loads	6/2/95
MOD 89-0011-00	Obsolete Type M-2 Vlv Actuators	8/23/01
MOD 97-0002-00	LM-Replace PDS 3886	7/17/98
C-EE-004.01-001	Protective Relay Setpoints for Service Water Pump Motor 1-1 (AC107)	5/12/98
C-EE-004.01-003	Protective Relay Setpoints for Service Water Pump Motor 1-3 (AC109)	10/27/92
C-EE-004.01-009	Protective Relay Setpoints High Pressure Injection Pump Motor 1-1 (AC111)	1/22/02
C-EE-004.01-010	Protective Relay Setpoints High Pressure Injection Pump Motor 1-2 (AD111)	6/21/91
C-EE-004.01-046	**4.16 KV Short Circuit Calculations**	**7/8/91**
C-EE-004.01-049	4.16 KV Bus Degraded Voltage (90 percent Undervoltage) Relay Setpoint	6/27/02
C-EE-004.01-051	59 percent Undervoltage (Loss of Station Power) Setpoint Calculation	8/23/93
C-EE-006.01-026	**Voltage Drop for GL 89-13 Valve Operators**	**5/21/02**
C-EE-006.01-027	SFAS Control Ckt Voltage Drop	5/4/92
C-EE-015.07-001	4.16 & 13.8 KV Cable Ampacity	5/7/92
C-ICE-048.01-002	SFAS Reactor Coolant Pressure Actuation Setpoints	10/14/97
C-ICE-011.01-001	**Service Water Pump Discharge Pressure Switches**	**4/19/01**
Op Eval 2000-0012 of CR 2000-2382	HPI Flow Indicating Switches	

Op eval 2001-0003 of CR 01-0138	4160 Breakers
Op eval 2001-0015 of CR 01-2158	HV SWGR Room HVAC
Op eval 2001-0025 of CR 01-2919	SFAS Sequencer

Please provide one line electrical schematics for the following:

13. Service Water Pumps
14. HPI Pumps
15. MOVs SW 1382, SW 1383, SW 5421, SW 5422, SW 5423, SW 5424, SW 5425, SW 2927, SW 2928
16. FCVs SW 5896, SW 5897

Please provide the nameplate data for the following pumps:

1. Service Water Pumps
2. HPI Pumps

Please provide the coordination calculations for all loads and feeder breakers for Buses AC and BD.

Please have available:

1. NEC Code
2. IEEE Std 242, "IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems." (IEEE Buff Book)
3. IEEE Std 141, "IEEE Recommended Practice for Electric Power Distribution for Industrial Plants." (IEEE Red Book)
4. Nuclear IEEE Standards, Volume 1 and 2

DOCUMENTS REQUEST FOR D. C. PREVATTE, 9/17/02

Please provide the latest revisions of the following documents.

In order to minimize unnecessary copying, for modification packages that are very large, please provide only the basic package "front-end" materials that describe the modification, its bases, etc., the 10CFR50.59 safety evaluation and/or screening, and the post modification testing documents, but not the detailed construction and installation documents. Likewise, for calculations that are very large, please provide only the basic "front-end" portions of the calculations, e.g., the purpose, assumptions, inputs, references, and results and conclusions sections, but not the large appendices.

Thank you for your support.

Modifications:

Modification #	Modification Title/Subject
For Service Water System:	
FCR 78-0039-2917	Change setpoints on PSH-2917
FCR 80-0225-00	Delete auto close SW 1395, 1399
FCR 80-0252-00	Replace valve bodies
FCR 80-0054-00	Back-up service water capability
FCR 84-0151-00	SWS valve & anchor modification
FCR 84-0111-00	Setpoint change - SW pump
FCR 84-0115-00	Changed SW valves locked position
FCR 84-0147-00	SW pump room ventilation upgrade
MOD 87-1072-00	Service water check valve
MOD 87-1075-00	Remove check valves SW-130, 134
MOD 87-1076-00	Remove check valves SW-217, 218
MOD 87-1290-00	Remove internals of SW-329
SCR 93-5016	Change PSL 1377 setpoint
FCR 80-0221-00	Piping change/service water
MOD 88-0234-00	Containment air coolers
MOD 94-0009-00	SW thermal relief valve replacement
For HPSI System:	
FCR 78-0414-00	Change Tech Spec 4.5.2.6
FCR 78-0498-00	Correct determination of FSAR
FCR 86-0291-00	Mod high pressure injection line

Calculations:

(Please note that some of these calculations appear from the title to address the same subject. If any of these are more current versions of the same analysis, or if any of these have been superceded by calculations not listed here, please provide only the most current calculations that address the subject.):

Calculation #	Calculation Title/Subject
For Service Water System:	
Mech 11.036	Traveling water screens
Struct 59	SW pipe stress analysis w/supports
Nucl 12501-M-001	UHS pond thermal performance analysis...
Nucl 12501-M-003	ECCS room temperature with initial 90 degree F forebay
Nucl 12501-M-004	UHS heat sink analysis of maximum evaporation period
Mech 59.001	UHS input
Mech 59-009	Davis Besse UHS
Mech 59-011	UHS analysis
Mech 59-016	UHS - Loss of intake canal - cooling pond calc
Mech 67.004	SW pump room - max allowable outside air temp to...
Mech 67.005	SW pump room ventilation capacity
Mech 67.006	SW pump room fan flow requirements
Mech 67.007	SW pump room ventilation system - pressure drop
Mech 67.008	SW pump room ventilation system - new penthouse...
Struct C-CSS-11.01-169	Containment air cooler eval for GL 96-06
Struct C-CSS-11.01-171	SW strainer internals analysis
Mech C-ME-011.01-130	SW system hydraulic calculation
Mech C-ME-011.06-003	Cont. cooler control valve travel
Nucl C-NSA-000.00-017	Service water system model
Nucl C-NSA-011.01-003	Allowable SW flow diversion during cold weather
Nucl C-NSA-011.01-004	SW pump start/coastdown time, CAC water hammer input
Nucl C-NSA-011.01-007	SW discharge through valve located at the intake struct.
Nucl C-NSA-001.01-008	Replacement of CAC flow control valves
Nucl C-NSA-001.01-010	Maximum SW pressure to AFW system
Nucl C-NSA-060.05-006	Revised containment response with 90 degree F SW
Nucl C-NSA-060.05-007	CAC duty at elevated SW inlet temperatures
Nucl C-NSA-060.05-008	Cont post-LOCA response w/variable SW temperature
Nucl ESM-99-002	Effect of UHS pond siltation on SW intake temperature

For HPSI System:

Mech 25.006	ECCS Rooms - Cooling System
Mech 25.013	ECCS Pump Room Heat Load
Mech 25.014	ECCS Pump Room Heat Load
Mech 32-1106901	MU/HP flow rates vs. reactor pressure...
Nucl 32-1159853	HPI flow vs. RCS pressure
Mech 36.010	LPI, HPI, CS pump NPSH from BWST

Mech 36.028	ECCS seal failure
Mech 36.031	HPI pump NPSH at a possible 1020 gpm
Mech 36.032	HPI pump test flow line
Mech 58.020	Flooding of ECCS pump rooms due to FW line break
Nucl 86-5006232	LOCA summary report
Mech C-ME-052.01-110	Reverse engineer HPI pump casing studs & casing nuts
Nucl C-NSA-032-02-003	Max allowable SW temp with inop ECCS room cooler
Nucl C-NSA-049.01-002	Adequacy of BWST for feed and bleed
Nucl C-NSA-049.01-004	Vortex formation with ECCS pump suction from the BWST
Nucl C-NSA-052.01-003	HPI pump acceptance testing
Nucl C-NSA-052.01-004	HPI system resistance curves
Nucl C-NSA-052.01-011	HPI NPSH on containment emergence sump recirc
Nucl C-NSA-052.01-012	Max. allowable leak rate through HP31/32
Nucl C-NSA-052.01-014	HPSI flow vs. RCS pressure for LOCA analysis input
Nucl C-NSA-052.01-016	Add “T” to HPI pump 2 discharge line
Nucl C-NSA-052.01-015	HPI pump curve based on system curve in LOCA analysis
Nucl C-NSA-063.01-008	Verification of HPI system performance during a SGTR
Nucl C-NSA-065.01-008	Makeup and HPI NPSH

Request for Documents Part III

Service Water Strainer

a. Drawings

b. Procedures, (surveillance, PMs, operating, abnormal,)

c. Maintenance history

d. Operational history (clogging events, identification of debris making it past the strainers, damage to the strainers, etc)

e. Last time opened for inspection, inspection results

f. Vendor Manual

g. Ultimate heat sink inspections, inspection results, maintenance and operational history,

h. Lay out drawing for the Service Water intake building (where the SW pumps are located)

i. For HPI pump #1 and SW pump #1 need the breaker relay vendor technical manual, the motor start curves and for HPI #1 motor need the name plate data

j. Do you have copies of the TS and UFSAR available on CDs?

Backup air supplies to the Containment Air Cooler (CAC) valves

k. Calculations for sizing

l. Basis calculation for the test acceptance criteria

m. Last two completed surveillance tests

Request for Documents Part IV

a. List of all work orders (preventive, corrective, troubleshooting, etc) for 4160 for the last two years.

b. Same as above except for service water system

c. Copy of Tech Spec Basis

d. Copy of annunciator response procedures for local and control room annunciators for service water and 4160

e. SBO D/G operating procedure DB-OP-06334

f. Implementing procedures for the following Tech Spec surveillance requirements:

    a. 4.8.2.1 - Onsite power dist systems

    b. 4.8.2.2 - Onsite power dist systems

    c. 4.6.3.1.2.a - containment iso valves

    d. 4.6.3.1.3 - containment iso valves

    e. 4.7.4.1.a - Service water system

    f. 4.7.4.1.b - Service water system

    g. 4.7.5.1 - UHS

    h. 4.8.1.1.1.a - Elect Power Systems

    i. 4.8.1.1.1.b - Elect Power Systems

g. The procedure performing and the last results for any snubbers in the service water system governed by SR 4.7.7

h. All IST procedures for the Service Water system components

i. One additional set of P&IDs for SW (sheets A, B, C)

j. Operability justifications and their associated CRS

a.	2001 - 0003	01-0138
b.	2001 - 0015	01-2158
c.	2002 - 0009	02-01157
d.	2002 - 0023	02-02658

k. Description of operability justification 2002 - 0027

l. EWR 02-0247-00 and CR 02-1459 and CR 02-2372 all dealing with operator work-around for intake chlorination

m. Copies of all other surveillance procedures preventive maintenance procedures and operator logs for SW and 4160.