UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

March 2, 2007

EA-07-047

R. T. Ridenoure
Vice President
Omaha Public Power District
Fort Calhoun Station FC-2-4 Adm.
P.O. Box 550
Fort Calhoun, NE 68023-0550

SUBJECT: FORT CALHOUN STATION - NRC BASELINE INSPECTION REPORT 05000285/2006018

Dear Mr. Ridenoure:

On February 13, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Fort Calhoun Station. A preliminary finding was discussed on December 21, 2006, with Mr. Jeff Reinhart, Site Director, and other members of your staff. After additional in-office review, a final exit meeting was conducted on February 13, 2007, with Mr. Reinhart and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. Specifically, the inspectors reviewed the circumstances surrounding a containment spray valve that was incorrectly installed on May 11, 2005. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

As described in Section 4OA5.5 of this report, inadequate Maintenance work instructions contributed to the improper configuration of containment spray header isolation Valve HCV-345. Specifically, the lack of detailed instructions or independent verifications, in steps for a maintenance procedure performed during the Spring 2005 refueling outage, resulted in the valve disk being installed improperly. This failure resulted in a condition where the actual position of the valve was nearly opposite of the indicated position. Additionally, your staff failed to identify the condition during postmaintenance testing. Consequently, this latent degraded condition existed for an entire operating cycle, approximately 454 days, until the condition revealed itself during the start of the Fall 2006 refueling outage. Based on review of circumstance related to this abnormal condition the NRC identified an apparent violation of 10 CFR Part 50, Appendix B Criterion V, "Instructions, Procedures, and Drawings" for failure to prescribe adequate procedures for maintenance and testing. The finding was characterized as an apparent violation and was preliminarily determined to have low to moderate (White) safety significance.

The condition did not represent an immediate safety concern at the time of discovery due to the plant being in a shutdown condition where the containment spray system was not required. The valve was reinstalled in a correct manner shortly after its condition was discovered, and prior to restart of the unit.

Regarding the preliminary characterization of the finding as an issue of low to moderate (White) safety significance, the NRC made this risk determination based upon review of the best available information at the conclusion of inspection activities. The preliminary risk determination is included as Attachment 2 to this report. We acknowledge that there are differences between the NRC risk assessment and those performed by your staff. The final resolution of this finding will convey the importance to safety by assigning the corresponding color (i.e., Green - a finding of very low safety significance; White - a finding with some increased importance to safety, which may require additional NRC inspection; Yellow - a finding with substantial importance to safety that will result in additional NRC inspection and potentially other NRC action; Red - a finding of high importance to safety that will result in increased NRC inspection and other NRC action). This finding appears to have increased safety significance because it represented a potential to create a flow diversion from the reactor coolant system during accident conditions. This finding is being considered for escalated enforcement action in accordance with the NRC Enforcement Policy. The current Enforcement Policy is included on the NRC's Web site at www.nrc.gov/OE.

Before we make a final decision on this matter, we are providing you an opportunity to (1) present to the NRC your perspectives on the facts and assumptions that were used by the NRC to arrive at the finding and its significance at a Regulatory Conference or (2) submit your position on the finding to the NRC in writing. In either case, to support our final significance determination, please provide your assessment of the risk significance of this issue. The assessment should include key assumptions and results of your estimates of changes to the core damage frequency and large early release frequency. Additionally, your assessment should include the following:

1) Your evaluation of the frequency of initiating events that can result in flow diversion from the reactor coolant system through Valve HCV-345 when the shutdown cooling system is placed in service.

2) Your evaluation of operator response to indications of a loss of reactor coolant system inventory, success paths available to prevent core damage, and perspectives on human reliability analysis for these scenarios.

3) Your evaluation of any contribution to the risk significance of this issue from external event initiators.

4) Any other detailed technical information or analyses you believe are important to support an overall risk assessment of the subject issue.

If you request a Regulatory Conference, it should be held within 30 days of your request, and we encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation, and will require Public Notice. If you decide to submit only a written response, your submittal should be sent to the NRC within 30 days of the receipt of this letter.

Please contact Jeffrey Clark at (817) 860-8147 within 10 business days of the date of the receipt of this letter to notify the NRC of your intentions. If we have not heard from you within

10 days, we will continue with our significance determination and enforcement decision and you will be advised by separate correspondence of the results of our deliberations on this matter.

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

In accordance with Code of Federal Regulations, Title 10, Part 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

A. Vegel, Deputy Director
Division of Reactor Projects

Docket: 50-285
License: DPR-40

Enclosure:
NRC Inspection Report 05000285/2006018
w/attachments: Supplemental Information; Significance Determination Evaluation

cc w/enclosure:
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SUNSI Review Completed: _JAC__ADAMS: ✓ Yes☐ No Initials: _JAC___
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RIV:RI:DRP/E	SRI:DRP/E	C:DRP/E	SRA:DRS	D:DRS
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-285
License:	DPR-40
Report:	05000285/2006018
Licensee:	Omaha Public Power District
Facility:	Fort Calhoun Station
Location:	Fort Calhoun Station FC-2-4 Adm. P.O. Box 399, Highway 75 - North of Fort Calhoun Fort Calhoun, Nebraska
Dates:	October 10 through February 13, 2007
Inspectors:	J. Hanna, Senior Resident Inspector L. Willoughby, Resident Inspector
Approved By:	A. Vegel, Deputy Director, Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000285/2006018; 10/10/2006 - 02/13/2007; Fort Calhoun Station; Other Activities.

This report documents the NRC's inspection of circumstances related to one train of containment spray being inoperable for 454 days. The baseline inspection activities were conducted by resident inspectors. The inspection identified one finding whose preliminary safety significance was determined to be low to moderate (White). The final significance of most findings is indicated by their color (Green, White, Yellow, or Red) using NRC Inspection Manual Chapter 0609, "Significance Determination Process." 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. NRC-Identified Findings and Self-Revealing Findings

Cornerstone: Mitigating Systems

- TBD. The team identified an apparent violation of 10 CFR Part 50, Appendix B, Criterion V, for the licensee's failure to prescribe adequate procedures for maintenance and testing on containment spray header isolation Valve HCV-345 which led to exceeding a Technical Specification allowed outage time. This issue was self revealed on September 13, 2006, when reactor coolant water issued from the containment spray header indicating that either Valve HCV-344 or Valve HCV-345 was not properly seated. The failure to perform adequate maintenance and testing for this component resulted in one train of containment spray being inoperable from May 11, 2005 to September 9, 2006, a period of 454-days. This exceeded the Technical Specification 2.4(2) allowed outage time of 24 hours when the reactor is critical.

  The issue was more than minor because it affected the equipment performance attribute of the Mitigating System Cornerstone due to the impact on availability and reliability of the containment spray system. The finding was preliminarily characterized under the significance determination process as having low to moderate safety significance (White) because one train of containment spray was left in a condition contrary to its design and may have represented a bypass flow path from the reactor coolant system during an accident condition. This condition was entered into the Omaha Public Power District's corrective action program as Condition Report 200604627. Valve HCV-345 was repaired by the licensee and is no longer safety concern. The finding has a crosscutting aspect in the area of human performance, specifically resources, in that complete and accurate procedures and work packages were not provided (Section 4OA5.5).

B. Licensee-Identified Violations

None.

REPORT DETAILS

4. OTHER ACTIVITIES

4OA5 Other Activities

1. Background of Maintenance History

During the Spring 2005 Refueling Outage, Omaha Public Power District (OPPD) performed work on the containment spray header isolation Valves HCV-344("A" Header) and HCV-345 ("B" Header) to address inconsistent operation identified during previous testing. On three separate occasions Valve HCV-345 was removed from the system, disassembled, reassembled, and returned to the system.

The function of the containment spray system is to limit the containment pressure rise and reduce the leakage of airborne radioactivity from the containment following a loss-of-coolant accident (LOCA) by providing a means for cooling the containment. This system reduces the leakage of airborne radioactivity by effectively removing radioactive particulates from the containment atmosphere. Pressure reduction is accomplished by spraying cool, borated water into the containment atmosphere, which provides a means for cooling the containment atmosphere. Heat removal is accomplished by recirculating and cooling the water through the shutdown cooling heat exchangers. The system is independent and redundant to the containment air cooling and filtering system. Removal of radioactive particulates is accomplished by spraying water into the containment atmosphere. The particulates become attached to the water droplets, which fall to the floor and are washed into the containment sump.

During the Fall 2006 Refueling Outage, the licensee inspected the valve seat rings, in part, to determine why reactor coolant water had leaked past the valve and had filled the spray headers inside containment. While performing this maintenance, the system engineer determined that the valve disk for Valve HCV-345 was installed nearly 90 degrees out of alignment. Actual valve position, while the valve was in this condition, was nearly opposite of the remotely indicated position. The resultant effect would be that if the valve indicated shut (the normal position of the valve) it would in fact be approximately 66 percent open. Conversely, if the valve received a valid demand signal to open (the safety position of the valve), it would be approximately 80 percent shut.

The time line below describes the major events and the maintenance history that resulted in Valve HCV-345 being installed incorrectly and not discovered until October 2006.

February 26, 2005	Refueling Outage 22 started.
March 17, 2005	Valves HCV-344 and HCV-345 removed from service and repacked per Work Order (WO) 178429-04 (1st occurrence).
March 25, 2005	Valves HCV-344 and HCV-345 reinstalled in the system.

May 3, 2005	Valves HCV-344 and HCV-345 removed from service and repacked per WO 205692-01 (2nd occurrence).
May 6, 2005	Valves HCV-344 and HCV-345 are reinstalled in the system.
May 7, 2005	Postmaintenance test of Valve HCV-345 identified that the valve did not stroke smoothly. Additionally, the drive shaft was protruding due to an incorrectly installed split ring retainer from the second installation, which prevented reinstallation of the cover plate.
May 9, 2005	Valve HCV-345 removed from service per WO 205692-01 (3rd occurrence). Improperly installed split ring retainer corrected and valve reinstalled in the system. During work the incorrect orientation between the drive shaft and the ball was introduced.
May 11, 2005	Work Order 205692 is completed and Valve HCV-345 returned to service.
May 30, 2005	Criticality achieved following Refueling Outage 22 and the unit recommences power operation.
June 4, 2005	Outage is started to replace degraded seals on Reactor Coolant Pumps A and B, which may have represented an opportunity to identify the incorrectly installed valve.
June 13, 2005	Criticality achieved following reactor coolant pump seal replacement outage and the unit recommences power operation.
April 29, 2006	Outage is started to replace a degraded seal on Reactor Coolant Pump D, which may have represented an opportunity to identify the incorrectly installed valve.
May 6, 2006	Criticality achieved following reactor coolant pump seal replacement outage and the unit recommences power operation.
September 9, 2006	Refueling Outage 23 started.
September 13, 2006	Reactor coolant water issues from the containment spray headers.
October 5, 2006	Work Order 234358-01 is processed to replace the seat ring on Valve HCV-345.
October 6, 2006	Valve HCV-345 is removed from the system.
October 10, 2006	System Engineer identified Valve HCV-345 assembled incorrectly and Condition Report 200604627 is written.

2. Cause Determination

The inspectors reviewed the accuracy and thoroughness of the licensee cause determination as represented in the lincesee's Root Cause Analysis Report, "Violation of Technical Specification 2.4.(1)a.iv. The Reactor Was Made Critical without the Minimum Required Operable Components."

The HCV 345 containment spray header isolation valve has a Fisher Type 657-8 diaphragm actuator and a Fisher Type U-1009 internal component including a Vee-Ball® disk within the valve. The disk is a wedge-shaped cross-section spanning an arc of 101 degrees. Along the disk's axis of rotation is a drive shaft that extends through the valve packing. On one end of the drive shaft are 16 splines that connect the drive shaft to a lever arm. The arm is pinned to a rod that is driven by the air-operator. In this manner, the vertical motion of the air diaphragm and valve shaft are converted to rotational motion of the ball disk, which should either allow or block flow. Proper operation of the valve depends upon two critical orientations: (1) the position of the Vee-Ball® disk relative to the splined drive shaft, and (2) the position of the drive shaft to the lever arm.

During the Spring 2005 refueling outage, maintenance was performed on Valve HCV-345 three times in accordance with Procedure PE-RR-VX-0401S, "Inspection and Repair of Fisher 300U/300UR Control Valves," Revision 2. The procedure directed maintenance personnel to mark the valve shaft to ensure proper alignment when reassembled. The first activity repacked the valve, and while it initially passed its pressure test, the packing started leaking the following day. The licensee then decided to install a different style of packing material. On the second disassembly to install the new packing, the split ring retainer was installed incorrectly. This prevented the drive shaft from being fully inserted into the Vee-Ball® disk and necessitated a third disassemble of the valve. During the third and final disassembly/reassembly, the drive shaft was inserted into the Vee-Ball® disk without ensuring that the orientation matched that found during disassembly. This resulted in the actual position of the valve being nearly opposite of the indicated position. Following reassembly and completion of the work package, Valve HCV-345 was returned to service.

The licensee identified that two failures had occurred. The first was that Valve HCV-345 was installed incorrectly. The licensee identified that the maintenance Procedure PE-RR-VX-0401S, "Inspection and Repair of Fisher 300U/300UR Control Valves," Revision 2 allowed flexibility of performing selected portions of the procedure and did not specify risk important steps that could impact final valve alignment. This was the root cause of the incorrect assembly. A contributing cause was that the maintenance personnel who annotated the step as "not applicable," did not recognize the importance of proper alignment between the drive shaft and disk, or believed (incorrectly) that installing the drive shaft with the packing box achieved the same result.

The second failure that was identified by the licensee was that postmaintenance testing failed to identify the incorrect assembly. The licensee determined that maintenance personnel had relied on an inadequate procedure without detailed acceptance criteria or verifications to ensure proper valve operation. This was the root cause as to why the postmaintenance test failed to identify the incorrect assembly. A contributing cause was that misleading markings may have been used to assess the valve position, as opposed to direct observation of the ball disk. Specifically, the many numerous match marks on the valve may have been confusing to the maintenance personnel.

The inspectors concluded that the causes identified by the licensee appeared correct and were achieved through a rigorous review of the circumstances surrounding the event.

3. Corrective Actions Taken Following Discovery of Condition

Following discovery of the misaligned valve condition, the licensee instituted or had planned a number of corrective actions including:

- Revised Procedure PE-RR-VX-0401S, “Inspection and Repair of Fisher 300U/300UR Control Valves,” to reference manufacturer’s index marks and remove direction to add additional match marks during disassembly.

- Revised Procedure PE-RR-VX-0401S, “Inspection and Repair of Fisher 300U/300UR Control Valves,” to provide acceptance criteria on verifying the valve open or closed as part of final reassembly and explicitly identify these steps as postmaintenance testing.

- Revised Procedure PE-RR-VX-0401S, “Inspection and Repair of Fisher 300U/300UR Control Valves,” to change the format of the procedure to allow partial performance such as during a packing replacement.

- Revised Procedure PE-RR-VX-0401S, “Inspection and Repair of Fisher 300U/300UR Control Valves,” to annotate risk-important steps (such as verification of valve position, i.e., postmaintenance test) and include a second verifier for these steps.

- Identification of all safety related air operated ball and butterfly valves, determination if any risk-important steps in the associated procedures required annotation and second verification, and/or verified that adequate post-maintenance testing existed with appropriate acceptance criteria. Inadequate procedures were to be revised.

These corrective actions were scheduled to be completed on/before February 28, 2007. The licensee also identified a number of enhancements that would not necessarily correct the condition or prevent recurrence, but would improve the maintenance program for these components. The inspectors noted that the following additional actions related to the misaligned valve condition had been taken or were planned:

- Evaluated the need for acquiring a mock-up of the HCV-345 valve for use in training personnel.

- Revised the Steamfitter Mechanic Training Program Master Plan to require Just-In-Time Training prior to outages where shutdown cooling heat exchanger outlet temperature control Valves HCV-341, HCV-344 or HCV-345 were going to be disassembled. (Please refer to Section 4OA5.4 below for a discussion of extent of condition and why these specific valves were identified).

- Evaluated whether work on valves similar to Valve HCV-345 should be treated as a separate training qualification.

- Included lessons learned from this event in the applicable training lesson plan for this model valve.

The inspectors found that the aforementioned corrective actions and enhancements appeared to be technically acceptable and appropriate. Though the inspectors were unable to predict with certainty the effectiveness of the corrective actions, the inspectors verified that the specified actions were planned or had been performed by the licensee at the completion of the inspection.

4. Extent of Condition Review

The inspectors evaluated the licensee's extent of condition review, specifically as it related to maintenance of other similar valves. This evaluation was performed to ensure that valves, or other components, that might have been subject to the same failure mechanism, were identified and corrected. The licensee identified three factors or "precursors" that contributed to the incorrect assembly of the valve. These included:

- Procedures that allowed performing certain steps for flexibility and to support differing work scopes.

- Risk important steps were not annotated in the procedures to provide a barrier when selecting steps to support a specific task.

- Equipment allowing alternate orientations for assembly (e.g., multiple splines on a shaft rather than a keyway, which would permit only one configuration).

The licensee reviewed maintenance procedures and components where all of the aforementioned elements might exist and lead to a similar failure. The licensee concluded that there was a low probability of these elements existing with respect to other components. Further, only three valves were identified as having a similarly designed shaft with multiple splines: Valves HCV-341, HCV-344, or HCV-345. Maintenance similar to that performed on Valve HCV-345 had been performed on Valve HCV-344 during the Spring 2005 refueling outage. On October 12, 2006, the licensee verified by direct visual inspection that Valve HCV-344 was installed correctly. A review of maintenance history records showed that Valve HCV-341 had never been removed from the system. Additional proof that Valve HCV-341 was correctly aligned was that this component was used to align the shutdown cooling system for continuous cooling of the core during the most recent refueling outage.

The licensee also reviewed the extent of condition for the failure of the post-maintenance test to identify the incorrect assembly. Specifically, maintenance practices were reviewed to determine if a successful postmaintenance test could be challenged by the failure of a single individual performing a risk important step. The licensee concluded that a concern existed, which was limited to the three valves mentioned above, nonsafety related pumps, and air operated ball and butterfly valves that are not containment isolation valves. The licensee developed corrective actions to address the extent of condition concern. (Please refer to Section 4OA5.3 of this report for a full description).

The inspectors reviewed the completed work orders on Valves HCV-344 and HCV-341 to ensure that during the most recent work on the components that the same failure mechanism was not introduced. The inspectors concluded that the licensee's extent of condition reviews were adequate to ensure that similar conditions did not exist elsewhere in the plant.

5. Maintenance Program

a. Inspection Scope

The inspectors reviewed the licensee's program for maintenance and inspection of pneumatically operated ball or butterfly valves, particularly as it related to the misalignment of Valve HCV-345 internals. The inspectors also examined the inspection/assessment techniques, scope, periodicity, and a sample of past inspection results. These reviews were conducted in order to assess the appropriateness of assigned postmaintenance testing for the scope of work performed.

b. Findings

Introduction. An apparent violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified for the licensee's failure to prescribe adequate procedures for maintenance and testing on containment spray header isolation Valve HCV-345, which led to exceeding a Technical Specification allowed outage time. This issue was self-revealed on September 13, 2006, when reactor coolant water issued from the containment spray headers indicating that either Valve HCV-344 or HCV-345 was not properly seated. The failure to prescribe adequate procedures for maintenance and testing for this component resulted in one train of containment spray being inoperable from May 11, 2005 to September 9, 2006, a period of 454-days. This exceeded the Technical Specification 2.4(2) allowed outage time of 24 hours when the reactor is critical.

Description. On September 9, 2006, the licensee shutdown the plant in order to commence Refueling Outage 23. On September 11, 2006, the licensee placed the shutdown cooling system in service to maintain cooling to the core. With this system in service, the two header isolation valves should prevent reactor coolant system water from entering the containment spray headers. On September 13, 2006, reactor coolant water issued from the containment spray headers indicating that either Valves HCV-344 or HCV-345 were "leaking." The licensee initiated work requests to evaluate the seat rings of Valve HCV-345. On October 10, 2006, a system engineer identified that the valve was assembled incorrectly and Condition Report 200604627 was written.

The inspectors identified several weaknesses in the maintenance and testing of Valves HCV-344 and HCV-345. Specifically, (1) though it was impractical to flow borated water to the containment spray headers following maintenance, these valves could have been tested using alternate means, (2) no independent verifications were performed during either the maintenance or subsequent testing, (3) the maintenance procedure allowed the flexibility to mark steps as “Not Applicable,” and (4) the procedure did not explicitly state which steps were de facto required postmaintenance testing and the importance of performing them correctly.

The inspectors determined that the postmaintenance testing performed following valve disassembly, packing adjustment and reassembly was inadequate to identify the misalignment of the valve internals. The postmaintenance testing requirements in Procedure PE-RR-VX-0401S, “Inspection and Repair of Fisher 300U/300UR Control Valves,” Revision 2, specified actions such as calibration of the valve actuator and performance of a valve actuator test. However, these steps would not have detected the condition that was present (i.e., valve internals installed backwards). The licensee relied on the aforementioned procedure to perform both the maintenance and postmaintenance testing without detailed acceptance criteria or independent verifications. The inspectors determined that the failure to have an adequate postmaintenance test constituted an apparent violation of NRC requirements.

Analysis. The inspectors assessed this issue using the Significance Determination Process (SDP). The inspectors concluded that the licensee’s failure to prescribe adequate proceures for maintenance and postmaintenance testing was reasonably within the licensee’s ability to foresee and correct, should have been prevented and thus constituted a performance deficiency. The failure to prescribe an adequate procedure for a postmaintenance test on Valve HCV-345 resulted in Containment Spray Train ‘B’ being inoperable from May 11, 2005, to September 9, 2006, a period of 454-days. The issue was more than minor because it affected the equipment performance attribute of the Mitigating System Cornerstone due to the impact on availability and reliability of the containment spray system. This finding has a crosscutting aspect in the area of human performance, specifically resources, in that complete and accurate procedures and work packages were not provided.

Though this condition was introduced while the plant was shutdown and likewise was discovered during a shutdown condition, the inspectors concluded that the condition should be reviewed using Inspection Manual Chapter 0609, Appendix A, “Determining the Significance of Reactor Inspection Findings for At-Power Situations.” This decision was based on the condition existing during and having safety significance (i.e., an adverse affect on systems responding to an accident) while at power.

Details of the Phase 2 evaluation and a Phase 3 SDP analysis are documented in Attachment 2. The preliminary results were that the finding was of low to moderate safety significance. The most significant contribution to the increase in risk involved accident scenarios where shutdown cooling was placed in service when containment sump recirculation was not required. This would result in a flow diversion from the reactor coolant system through the containment spray header that required operators to diagnose and act upon.

Enforcement:

10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to this, the licensee failed to develop appropriate instructions or procedures for maintenance activities, and post maintenance testing, on Valve HCV-345. This failure resulted in one train of containment spray being inoperable from May 11, 2005 to September 9, 2006, a period of 454 days. This item has been entered into the licensee’s corrective action program as Condition Report 20064627. Pending determination of final safety significance, this finding is identified as an apparent violation (AV) 05000285/2006018-01, “Violation of 10 CFR 50, Appendix B Criterion’s for Failure to Prescribe Adequate Procedures for Maintenance and Testing.” (Section 40A5.5)

6. Operability of Valve HCV-345 Following Repair Activities

The inspectors reviewed the documented test data, including photographs of the as-left condition of the valve, to verify that the testing was complete and that the equipment was able to perform the intended safety function. No issues or concerns were identified.

7. Potential Common Failure Modes and Generic Safety Issues

The inspectors performed searches of operating experience (OE) databases and other sources. The intent was to identify OE reports of similar problems, both within and outside of the nuclear industry. Through a review of the licensee’s condition reporting system, the inspectors identified one instance of relevant information that was not discovered by the licensee prior to the time that the condition was introduced in the Spring 2005 outage. This involved a Fisher Information Notice 2002-01, “Fisher Type SS-84 Vee-Ball® Seat Leakage Information,” which described a possible misalignment of the internal components. Specifically it stated, “If the connections between the lever and valve shaft or the valve shaft and Vee-Ball® are not correctly aligned, there is a possibility that the Vee-Ball® will not be correctly positioned to provide shutoff when the actuator strokes to the closed position.” This OE had been reviewed by the licensee and deemed not applicable because it was a slightly different valve model. The inspectors considered that the design of the components were similar to the ‘U’ model Fisher valves installed at Fort Calhoun Station. The inspectors found no other examples of internal OE.

With respect to external OE, the inspectors identified three instances where Fisher Vee-Ball® valves were incorrectly assembled at other nuclear facilities. Two of these occurrences, which happened during the 2004/2005 time frame, had also been identified by the licensee through the reviews performed by the Root Cause Analysis team responding to this event. For these two items, the licensee had entered the information into their OE tracking system and assigned review of those items to engineering personnel. In reviewing both OE items, the engineering staff incorrectly concluded that the information was not relevant to the Fort Calhoun Station.

The inspectors found additional OE in the form of an Event Report from Vogtle Electric Generating Plant - Unit 2. As described in Licensee Event Report 05000425/1989-031-00, “Heater Drain Tank Valve Reassembly Error Leads to Turbine/Reactor Trip,” an error involving reassembly of the valve led to the transient. The cause was described as follows:

> “Since the valve was not to be removed from the line, the maintenance crew that removed the actuator had match-marked the valve in the open position. A second maintenance crew had rebuilt the actuator and reinstalled it using the maintenance match marks. A third crew had tested the valve operation and reinstalled the position indication to match the actuator piston position. After the reactor trip, the maintenance match marks were checked and were found to disagree with the valve position indication by 90º. It was then realized that a reassembly error had occurred in that the actuator piston had been in the closed position when the actuator was reinstalled . . . ”

The inspectors did not identify any documents that had evaluated this condition at the Fort Calhoun Station. Though the inspectors noted that it would not have been reasonable to expect a licensee to review all Licensee Event Reports issued from other facilities for potential applicability, this event represented another example of improper assembly of Fisher valves that had safety consequences.

The inspectors concluded that the licensee had missed multiple opportunities, some of which were both recent and relevant, to identify the vulnerability to the possible misalignment of Fisher valve internals.

4OA6 <u>Meetings, Including Exit</u>

A preliminary finding was discussed on December 21, 2006, with Mr. Jeff Reinhart, Site Director, and other members of your staff. After additional in-office review, a final exit meeting was conducted on February 13, 2007, with Mr. Reinhart and other members of your staff. The inspectors confirmed that proprietary information was not provided during the inspection.

ATTACHMENT 1: SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

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LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000285/2006018-01	AV	Violation of 10 CFR part 50, Appendix B, Criterion V "Instructions Procedures, and Drawings" for failure to Prescribe Adequate Procedures Maintenance and Testing. (Section 4OA5.5)

LIST OF DOCUMENTS REVIEWED

USAR Section 6.0, Engineered Safeguards

USAR Section 9.3, Shutdown Cooling

Preventative Maintenance records for Valves HCV-344 and HCV-345

Procedure PE-RR-VX-0401S, "Inspection and Repair of Fisher 300U/300UR Control Valves," Revision 2

Procedure OP-ST-SI-3002, "Safety Injection System Category A, B, and C Valve Exercise Test," Revision 24

Procedure OP-ST-VX-3019, “Safety Injection System Remote Position Indicator Verification Surveillance Test,” Revision 15

Work Order 00205692-01, “Rebuild/Replace Packing - HCV-345"

Work Order 00229974-01, “Replace IA-HCV-341-B1 Tie-Wraps with Tube Clamps”

Work Order 00200552-01, “HCV-341: Clean Boric Acid from Affected Areas”

Work Order 00206035-01, “Rebuild/Replace Packing - HCV-344"

Root Cause Analysis Report, “Violation of Technical Specification 2.4.(1)a.iv The Reactor Was Made Critical without the Minimum Required Operable Components”

Reactor Plant Event Notification Worksheet for Event #42512, dated April 19, 2006

Reactor Plant Event Notification Worksheet for Event #42896, dated October 10, 2006

Licensee Event Report 05000285/2006-005, “Faulty Maintenance Renders One Train of Containment Spray Inoperable”

Condition Reports:

CR 200604627	CR 200604695	CR 200605311	CR 200605315	CR 200605348
CR 200605350	CR 200605352			

Maintenance Rule Cause Determination 08190610 for Condition Report 200604695

System Training Manual, Volume 15, “Emergency Core Cooling System,” Revision 35

LIST OF ACRONYMS

CFR	Code of Federal Regulations
CR	Condition Report
LOCA	Loss-of-Coolant Accident
OE	operational experience
NRC	Nuclear Regulatory Commission
SDP	Significance Determination Process
USAR	Updated Safety Analysis Report
WO	work order

ATTACHMENT 2: SIGNIFICANCE DETERMINATION EVALUATION

Significance Determination Process Phase 2 Risk Estimation:

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, “User Guidance for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” the inspectors evaluated the subject finding using the Risk-Informed Inspection Notebook for Fort Calhoun Station, Revision 2 (The “Phase 2 Notebook”). The inspectors and a senior reactor analyst discussed the applicability of worksheets in the Phase 2 Notebook. Modifications were required. In particular, the licensee's risk analysis staff identified a potentially significant initiating event involving an interfacing system LOCA (ISLOCA) from failure of a reactor coolant pump (RCP) seal cooler. The senior reactor analyst determined that this initiator could be modeled by using the ISLOCA worksheet of the Phase 2 Notebook with a transfer to the SLOCA worksheet. Therefore, a "Modified" Phase 2 SDP risk estimation was performed as described below.

Modified Significance Determination Process Phase 2 Risk Estimation:

Risk Estimation with Containment Spray (CS) Train B Not Functional

The following assumptions were made:

- Containment Spray (CS) Train B was not functional with the internals of Valve HCV-345 installed incorrectly. The licensee's Root Cause investigation determined that with closed indication, the valve was approximately 66 percent open; and, with open indication, the valve was only about 20 percent open. For this analysis, no containment temperature or pressure control credit was given for any reduced flow through the partially-open valve. The licensee subsequently performed a thermal-hydraulic analysis to demonstrate success of the Train ‘B’ CS system with degraded flow from a 20-percent open valve. This will be addressed later.

- The exposure time was determined by identifying the length of time the CS system was required to be operable from May 11, 2005, when Valve HCV-345 was assembled incorrectly, to October 10, 2006, when the condition was discovered. The resulting exposure time was 454 days. Therefore, the “greater than 30 days” exposure window was used in Table 1 of the SDP Notebook to determine the Initiating Event Likelihood (IEL).

- Table 2, "Initiators and System Dependency," of the Phase 2 Notebook required that all Initiating Event Scenarios be evaluated except for Steam Generator Tube Rupture (SGTR), Anticipated Transient Without Scram (ATWS), and Loss of Raw Water (LRW). The inspectors and analyst determined that exclusion of SGTR was a typographical error in the Phase 2 Notebook because CS was a credited safety function for mitigating a SGTR. Therefore, the SGTR worksheet was solved.

- Train B of CS was associated with 125 VDC Bus 2. Therefore, when the Loss of 125 VDC Bus 1 (LCDBUS1) worksheet was solved, the remaining mitigation capability for the CS function was zero. When the Loss of 125 VDC Bus 2 (LDCBUS2) worksheet was solved, the sequence involving the CS function was included at its base-case value to reflect the reduction in system reliability.

- The Component Cooling Water (CCW) system provides cooling water to the Containment Air Cooling and Filtering System. This CCW flow is divided among four cooling units in two trains. CCW is supplied to the VA-1A and VA-1B cooling coils of the Containment Cooling and Filtering Units (VA-3A and VA-3B) and the VA-8A and VA-8B cooling coils of the Containment Cooling Units (VA-7C and VA-7D). The containment pressure and temperature control safety function provided by the Containment Air Cooling and Filtering System is redundant to the CS system.

- The Raw Water (RW) system is a backup for most of the components supported by the CCW system, including the containment cooling coils. However, the licensee does not credit RW for success of containment cooling. The lower pressure of the RW system when supplied to the containment coolers may result in two-phase flow and inadequate heat removal capabilities. Therefore, RW backup to the containment cooling coils was not credited for success of containment temperature and pressure control but it was credited for successful cooling of the ECCS pumps and the SDC heat exchangers.

- The CCW system provides cooling to the reactor coolant pump (RCP) thermal barrier and integral heat exchanger for controlled bleedoff flow seal cooling. The licensee's system training manuals state that on an RCP seal cooler heat exchanger tube rupture, an ISLOCA can occur in the auxiliary building due to transfer of reactor coolant to the CCW system. This high-pressure fluid was expected to rupture the CCW surge tank and cause loss of CCW function. In this event, operators are instructed to close the CCW containment supply and return isolation valves to the RCP seal coolers (HCV-438A/B/C/D). Closure of these valves would terminate the ISLOCA outside of containment but was expected to result in a SLOCA inside of containment because of failure of the 150 psig (design pressure) CCW system piping. The licensee's PRA estimated that the frequency of an RCP seal cooler tube failure was 3E-4/yr. Therefore, the analyst modeled this event as equivalent to a SLOCA with IEL = 4. The remaining mitigation capability credit for containment temperature and pressure control was estimated as a single train system, represented by the remaining functional CS Train ‘A' (CNT = 2).

- No credit was given for operator recovery of the failed CS Train B. Recovery of the failed train required repair of HCV-345, which did not meet the acceptance criteria for operator recovery credit.

- An interface exists between the CS and low-pressure safety injection (LPSI) systems because both systems can use the SDC heat exchangers. During a normal shutdown and transition to SDC, operators enter containment and close

CS manual isolation Valves SI-177 and SI-178 to preclude SDC flow from entering the CS headers and spraying the containment if leakage existed through Valves HCV-344 or HCV-345. However, if an accident occurred that involved operators initiating SDC prior to a recirculation actuation signal (RAS) in accordance with Emergency Operating Procedure (EOP) Attachment 4, "SDC Without RAS," the finding had the potential to create a flow diversion from the RCS. The manual valves are not closed during implementation of Attachment 4. Remotely-operated Valves HCV-344 and HCV-345 would be closed and relied upon for providing isolation of SDC from the CS headers. When operators initiated SDC, flow would be diverted from the RCS through the CS header and unavailable for core cooling even though Valves HCV-344 and HCV-345 had been closed. This flow diversion to the CS header is assumed to fail the SDC function. **However, the Phase 2 Notebook does not credit the SDC safety function for mitigating any initiating events and is not evaluated further in this Modified Phase 2 analysis. It will be addressed later.**

<u>Modified Phase 2 Analysis Results Internal Events</u>:

Using the above assumptions, the Modified Phase 2 Analysis results for the non-ISLOCA initiator worksheets are shown below.

SEQUENCE	IEL	REMAINING MITIGATION CAPABILITY RATING	RECOVERY CREDIT	RESULTS
TRANS-PCS-AFW-CNT	1	3+5+5	0	14
TPCS-AFW-CNT	1	3+5	0	9
SLOCA-CNT	3	5	0	8
SORV-BLK-CNT	4	2+5	0	11
MLOCA-CNT	4	4	0	8
LLOCA-CNT	5	4	0	9
LOOP-AIAFW-MDAFW-CNT	2	3+2+5	0	12
SGTR-SHR-CNT	3	7+5	0	15
MSLB-MSIV2-AFW-CNT	3	2+5+5	0	15
SEQUENCE	**IEL**	**REMAINING MITIGATION CAPABILITY RATING**	**RECOVERY CREDIT**	**RESULTS**
LDCBUS1-AFW-CNT	3	2+2	0	7
LDCBUS2-AFW-CNT	3	5+4	0	12
LCCW-AFW-CNT	3	3+5	0	11
LCCW-SEAL-CNT	3	4+5	0	12
LCCW-RCPTRIP-CNT	3	3+5	0	11

LIA-AFW-CNT	2	3+5	0	10

The Modified Phase 2 analysis results for the RCP seal cooler ISLOCA initiator are shown below.

SEQUENCE	IEL	REMAINING MITIGATION CAPABILITY RATING	RECOVERY CREDIT	RESULTS
SLOCA-CNT	4	2	0	6

Using IMC 0609, Appendix A, Attachment 1, Table 5, “Counting Rule Worksheet,” the summation of the non-ISLOCA and the ISLOCA sequences is equivalent to one sequence with a risk significance equal to 6. Therefore, the Modified Phase 2 SDP Analysis result of the risk significance of this finding due to internal events is of low-to-moderate safety significance (White).

Modified Phase 2 Analysis - Large Early Release Frequency (LERF)

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.6, "Screening for the Potential Risk Contribution Due to LERF," the analyst reviewed the core damage sequences to determine an estimate of the change in LERF caused by the finding.

The analyst considered the RCP seal cooler failure with ISLOCA outside of containment initiator to be part of the plant's baseline risk, up to the point of when the ISLOCA was isolated to the containment. From that point, the event transferred to the SLOCA event tree, which did not result in a sequence causing a change in LERF. The only other sequence considered applicable for LERF was one SGTR sequence, but it was a negligible contributor. Therefore, for the Modified Phase 2 SDP risk estimation this finding was considered not significant with respect to an increase in LERF.

Modified Phase 2 Analysis - External Events

In accordance with Inspection Manual Chapter 0609, Appendix A, Attachment 1, Step 2.5, "Screen for the Potential Risk Contribution Due to External Initiating Events," experience with using the Site Specific Risk-Informed Inspection Notebooks has indicated that accounting for external initiators (fire, flooding, severe weather, seismic, or others) could result in increasing the risk significance attributed to an inspection finding by as much as one order of magnitude.

The Modified Phase 2 Analysis result met the criterion for consideration of risk contribution due to external events (risk estimation increase greater than or equal to 1E-7 per year). Although the Phase 2 Notebook for Fort Calhoun Station does not currently include external events, the analyst and inspectors qualitatively reviewed external event applicability. The results of this review were that fire events may be applicable. However, the fire events were limited to affecting the SDC function, which was not evaluated in the Modified Phase 2 analysis. Therefore, the contribution due to external events for the Modified Phase 2 analysis was assumed to be negligible and the preliminary significance determination could be represented solely by the contribution from internal events.

Consideration of Reduced CS Flow vs. Zero CS Flow on Success of CNT Function (Modified Phase 2 Analysis with CS Train B Functional)

The licensee informed the analyst that the MAAP accident analysis code was used to evaluate plant response to a severe accident using the as-found configuration (20-percent open) of Valve HCV-345 with reduced CS flow. The results of these analyses were documented in PRA Modeling Position White Paper CCF 107-001, "Impact of the HCV-345 Mis-Installation on Containment Performance During Severe Accidents." The licensee concluded the as-found condition of Valve HCV-345 would provide sufficient CS flow to mitigate a LLOCA, even with no containment coolers or CS flow from the unaffected CS Train 'A'. This analysis was not reviewed by NRC staff. However, HCV-345 is a ball valve, and qualitatively would be expected to allow a significant fraction of its fully-open flow even if it were only 20-percent open.

Assuming the licensee's analysis was correct, the CS system would receive "multi-train" credit when determining remaining mitigation capability credit for the CNT safety function. This additional credit added a "1" to each of the sequence results obtained above. Therefore, the Modified Phase 2 Analysis result for internal events was equivalent to one sequence with a risk significance equal to 7, which is a Green result.

As described previously, the SDP Phase 2 Notebook did not include a means to assess findings affecting the SDC safety function. This finding was determined to not only affect the performance of CS, but also the performance of SDC if it was initiated in an accident without a RAS. Therefore, a Phase 3 SDP Analysis was required to address this impact.

Phase 3 SDP Analysis: Consideration of Additional Severe Accident Scenarios Involving Initiation of SDC When a RAS Has Not Occurred

The licensee identified that a flow diversion path would be created from the RCS to the CS header if SDC were placed in service without having closed the inside-containment manual isolation valves. When Valve HCV-345 was closed by the control room operator, it would have indicated closed but have remained 66 percent open. For events that required the operators to initiate SDC when a RAS had not occurred, a flow diversion from the RCS through the CS header would fail the SDC function. The licensee's analysis is documented in a white paper, "Severe Accident (PRA) Perspective Regarding Improper Positioning of Containment Spray Header Isolation Valve HCV-345."

The licensee performed a screening review to determine what initiating events were likely to progress to SDC initiation without having previously resulted in a RAS. For those events, the operators would be directed to implement EOP/AOP Attachment 4, "SDC Without RAS." The results of the screening review were:

For LLOCAs and MLOCAs, SDC will not be initiated prior to a RAS. Therefore, they were excluded.

> For SLOCAs with HPSI flow greater than 220 gpm, the licensee's analysis concluded that at the time the SDC suction valves were opened, HPSI flow was already sufficient to prevent core damage with no additional operator actions.
>
> For SLOCAs with HPSI flow < 220 gpm and for SGTR and MSLB/FWLB events, the licensee's analysis concluded that at the time the SDC suction valves were opened, core damage would occur in 90 minutes if operators did not diagnose the loss of inventory and take action to isolate the leak path. The licensee determined that the frequency of these initiating events was 1.4E-2/year.
>
> The licensee qualitatively screened out other initiating events from consideration. They concluded it was improbable for other events to proceed to SDC without RAS.

The analyst noted that EOPs to address other initiators (such as EOP-02, "Loss of Off-Site Power/Loss of Forced Circulation," and EOP-06, "Loss of All Feedwater") contained provisions to initiate SDC using EOP/AOP Attachment 4. Therefore, other initiators not included in the licensee's assessment could add to the total risk. The analyst was not able to verify the licensee's qualitative determination that the other initiators were not probable.

The licensee's analysis described the following evaluation for the severe accident scenarios under consideration:

> Once the operators had successfully achieved plant conditions to support initiating SDC, they would begin to implement EOP/AOP Attachment 4. When both SDC valves were opened from the RCS, the operators would be presented with audible and visible cues that a loss of RCS inventory was occurring. Among them were: pressurizer low level alarms and containment sump level alarms. The crew would then diagnose that a loss of RCS inventory was taking place and take action to terminate the inventory loss by closing a SDC suction valve. Failure of both SDC suction valves to close due to common cause was qualitatively considered in the licensee's assessment but discounted. The licensee concluded that should this occur, sufficient time was available to identify and close another isolation valve, including manual valves. After terminating the RCS inventory loss, heat removal could continue for an indefinite amount of time using the steam generators. HPSI flow could be established if necessary.

The licensee performed a human reliability assessment to estimate the total human error probability (HEP) for failing to diagnose the loss of inventory and act to stop it. The licensee's estimation used the NRC's SPAR-H Human Reliability Analysis Method and is summarized as follows:

> The licensee estimated that once the loss of inventory began, a maximum of 1 minute of delay time would exist prior to the visual and audible cues that a loss of inventory was occurring. Then the licensee estimated that 1 minute would be

required to diagnose the problem and decide upon an action. Another 1 minute was estimated for an operator to complete the required action to terminate the loss of inventory. The total time available before core damage was 90 minutes.

The licensee assessed the SPAR-H performance shaping factors (PSF) for the diagnosis and action components of this task, selected PSF multipliers, and determined the task HEP without formal dependence as follows:

PSF	**Diagnosis Multiplier (Base = 0.01)**	**Action Multiplier (Base = 0.001)**
Available Time	Extra Time (0.1)	>=50x time required (0.01)
Stress	Nominal (1.0)	Nominal (1.0)
Complexity	Obvious Diagnosis (0.1)	Nominal (1.0)
Experience/Training	Nominal (1.0)	Nominal (1.0)
Procedures	Diagnostic/symptom oriented (0.5)	Nominal (1.0)
Ergonomics	Nominal (1.0)	Nominal (1.0)
Fitness for Duty	Nominal (1.0)	Nominal (1.0)
Work Processes	Nominal (1.0)	Nominal (1.0)
SUBTOTAL	5.0E-5	1.0E-5
TOTAL	6.0E-5	

Based on additional discussions the analyst had with the licensee regarding the HRA, the licensee confirmed that HPSI would be available as a mitigation option if the SDC flow diversion path was not terminated. HPSI would likely have been operating, and throttled at the time SDC was initiated. The licensee considered the above HRA for diagnosis/action to terminate the diversion path to be a simplification. Additional diagnoses/actions would have further complicated the HRA. However, the licensee stated that during this scenario, Safety Function Status Checks would have been performed. One of the checks includes monitoring pressurizer level and restoring as necessary. Monitoring HPSI stop and throttle criteria is a floating step in the EOPs. The licensee stated that this is why they considered a "Nominal (1.0)" multiplier appropriate for the Procedures - Action PSF.

The senior reactor analyst reviewed the licensee's assessment and concluded that some changes to the PSF multipliers selected by the licensee were needed. Using NUREG/CR-6883 as a reference, the following changes were made:

Changed the Available Time PSF multiplier for Diagnosis to “Expansive Time” because the average time for diagnosis was 1 minute, the time available was greater than twice the average time, and was greater than 30 minutes.

Changed the Stress PSF multipliers for Diagnosis and Action to “High.” The analyst assumed that the task would be performed in a condition of higher-than-nominal stress, with multiple unexpected alarms at the same time, and that the consequences of the task represent a threat to plant safety.

Changed the Procedures PSF multiplier for Action to "Incomplete." EOP/AOP Attachment 4 did not contain instructions for what response action the operator should take to complete the task. Therefore, no credit for procedures could be given for this task.

The analyst's revised HEP assessment was as follows:

PSF	Diagnosis Multiplier (Base = 0.01)	Action Multiplier (Base = 0.001)
Available Time	Expansive Time (0.01)	>=50x time required (0.01)
Stress	High (2.0)	High (2.0)
Complexity	Obvious Diagnosis (0.1)	Nominal (1.0)
Experience/Training	Nominal (1.0)	Nominal (1.0)
Procedures	Diagnostic/symptom oriented (0.5)	Incomplete (20.0)
Ergonomics/HMI	Nominal (1.0)	Nominal (1.0)
Fitness for Duty	Nominal (1.0)	Nominal (1.0)
Work Processes	Nominal (1.0)	Nominal (1.0)
SUBTOTAL	1.0E-5	4.0E-4
TOTAL	4.1E-4	

The analyst requested peer review of the analysis by staff from the Office of Nuclear Reactor Regulation. Some changes were proffered, particularly involving the Procedures PSF multiplier for Action. The staff believed some credit may be warranted for the Procedures PSF by crediting use of other procedures (e.g., functional restoration procedures and initiation of emergency core cooling). Although some reduction in the HEP would result from this change, the operator actions would involve and require a diagnosis and action approach different than the one explicitly analyzed here. This approach would involve additional PSF multiplier changes for diagnosis and action that may decrease available time, increase complexity, etc. Therefore, the staff concluded the analyst's HEP assessment result was a reasonable estimate given available information.

Phase 3 Analysis Conclusion for Severe Accident Scenarios Involving SDC to CS Flow Diversion (Internal Events)

The increase in core damage frequency due to internal events associated with the finding is estimated as the product of the initiating event frequency for events that result in an RCS flow diversion when SDC is placed in service, times the HEP for the task of diagnosing and terminating the loss of inventory.

The result using the licensee's HEP estimate is:

1.4E-2/year * 6.0E-5 = 8.4E-7/year

The result using the analyst's HEP estimate is:

1.4E-2/year * 4.1E-4 = 5.7E-6/year

Therefore, the preliminary significance of this finding due to the increase in core damage frequency associated with internal events was determined to be of low to moderate safety significance (White).

<u>Phase 3 Analysis - External Events Assessment</u>

The inspectors and senior reactor analyst qualitatively assessed the contribution due to external initiators. The only contributor considered to potentially be significant was fire scenarios. Valves HCV-344 and HCV-345 are on the licensee's safe shutdown components list in the Fire Hazards Analysis. The valves are identified as having a necessary function to close to prevent diversion of SDC flow through the CS headers.

The safe shutdown time line indicated that SDC would be established 13 hours after a fire event and therefore was not considered a time critical activity. The inspectors determined that in a control room fire scenario, the licensee would be implementing AOP-6, "Fire Emergency." AOP-6 identified the potential for spurious operation of Valves HCV-344 and HCV-345 and proceduralized containment entry to close SI-177 and SI-178 prior to initiating SDC. In other fire scenarios, SDC would also be initiated using normal system operating procedures which would specify containment entry to close the manual isolation valves. Based on this discussion, the analyst considered that fire events did not contribute to the risk significance of this finding. Other external initiators were considered by the analyst to be negligible.

The licensee had not performed an assessment of external initiators at the time of this analysis.

<u>Phase 3 Analysis - LERF Assessment for Severe Accident Scenarios Involving SDC to CS Flow Diversion</u>

The increase in risk associated with LERF is considered if the increase in core damage frequency is greater than 1E-7/year. Core damage sequences involving a SGTR initiating event are important with respect to LERF and have a LERF multiplier of 1.

However, use of a LERF multiplier of 1 does not address that the SGTR sequences of interest here would only include those where the SGTR was successfully mitigated to the point of initiation of SDC. Therefore, the analyst believed the LERF multiplier would be much less than 1. Following discussion with staff in the Office of Nuclear Reactor Regulation, the analyst used a 0.1 LERF multiplier to estimate the significance of sequences contributing to LERF.

To determine the contribution in risk due to LERF, the analyst used the frequency of SGTR events from the licensee's PRA, multiplied times the HEP for SDC failure. Then, this CDF for SGTR events was multiplied times the LERF multiplier to obtain the LERF estimate.

For the licensee’s HEP estimate:

SGTR CDF = 5.91E-3/year * 6.0E-5 = 3.6E-7/year

With a LERF multiplier of 0.1, the increase in LERF is 3.6E-7/year * 0.1 = 3.6E-8/year

For the analyst’s HEP estimate:

SGTR CDF = 5.91E-3/year * 4.1E-4 = 2.4E-6/year

With a LERF multiplier of 0.1, the increase in LERF is 2.4E-6/year * 0.1 = 2.4E-7/year

Therefore, using the analyst's estimate, the risk significance of this finding with respect to LERF is White because the result is greater than 1E-7/year.

<u>Confirmatory Phase 3 Analysis Using the SPAR Model</u>

Using the Fort Calhoun Station SPAR Model, Revision 3.31, the senior reactor analyst attempted to independently model and quantify an increase in core damage frequency due to the finding.

For simplicity, the analyst accepted the licensee’s assertion that degraded CS flow through HCV-345 was sufficient for successful CS function. The ISLOCA initiator, although it failed CCW and its containment cooling function, did not affect the functionality of CS. The resulting LOCA inside of containment was assumed large enough to require a RAS. Therefore, the RCP seal cooler failure and ISLOCA scenario was eliminated from consideration.

Several of the initiating event trees in the SPAR model contained a top event for the SDC function. The containment spray header isolation Valves HCV-344 and HCV-345 were included in the SPAR model for success of the CS function (required to open). However, these valves were not included in the SPAR model for the SDC function (required to close). Therefore, the SDC flow diversion path was not modeled in the SPAR model. The analyst chose a SPAR model basic event that would fail the SDC function as a surrogate for the need to model the flow diversion path. By inspection of the initiating event trees and fault trees, the analyst determined failing the SDC heat exchanger outlet valve HCV-341 closed would provide an acceptable surrogate for modeling the SDC flow diversion scenario while allowing credit for high-pressure injection and sump recirculation.

Basic Event SDC-AOV-CC-CLI, “SDC Discharge AOV HCV-341,” was set equal to TRUE (failed closed). For a 1-year exposure time, the calculated importance was 1.0E-6. The top three core damage sequences all involved SGTR and represented almost all of the total increase in risk. The next two sequences involved a transient and a loss of all feedwater, but they were much lower in significance.

In conclusion, this confirmatory Phase 3 analysis using the SPAR model demonstrated that the risk significance of this finding due to internal events was an increase in core damage frequency of 1.0E-6/year. This met the threshold for a finding of low-to-moderate safety significance (White). With respect to LERF, most of the contribution to risk associated with this finding was the result of SGTR sequences. Therefore, the analyst concluded that the significance of this finding with respect to LERF was also White (increase in LERF greater than 1E-7/year).

References

Risk-Informed Inspection Notebook for Fort Calhoun Station, Revision 2, September 30, 2005

Fort Calhoun SPAR model, Revision 3.31, April 10, 2006

NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method"

Fort Calhoun White Paper, "Severe Accident (PRA) Perspective Regarding Improper Positioning of Containment Spray Header Isolation Valve HCV-345"

USAR Section 4.3, Reactor Coolant System, Component and System Design and Operation

USAR Section 6.3, Engineered Safeguards, Containment Spray System

USAR Section 6.4, Engineered Safeguards, Containment Air Cooling and Filtering System

USAR Section 7.3, Instrumentation and Control, Engineered Safeguards Controls and Instrumentation

USAR Section 9.3, Auxiliary Systems, Shutdown Cooling System

USAR Section 9.7, Auxiliary Systems, Component Cooling Water System

System Training Manual Volume 8, Component Cooling Water System

System Training Manual Volume 10, Containment Structure and Ventilation System

System Training Manual Volume 15, Emergency Core Cooling System

AOP-6, "Fire Emergency"

EOP-00, "Standard Post Trip Actions"

EOP-02, "Loss of Off-site Power, Loss of Forced Circulation"

EOP-03, "Loss of Coolant Accident"

EOP-04, "Steam Generator Tube Rupture"

EOP-05, "Uncontrolled Heat Extraction"

EOP-06, "Loss of all Feedwater"

EOP-20, "Functional Recovery Procedure"

EOP/AOP Attachments, Attachment 4, "SDC Without RAS"