APPENDIX C

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-285/89-40 Operating License: DPR-40

Docket: 50-285

Licensee: Omaha Public Power District (OPPD)
444 South 16th Street Mall
Omaha, Nebraska 68102-2246

Facility Name: Fort Calhoun Station

Inspection At: Blair, Nebraska

Inspection Conducted: October 23 through 27, and November 6 through 9, 1989

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Inspection Summary

A special, announced team inspection of critical components of the plant and the operational activities relating to dominant accident sequences developed by a generic-based risk assessment. The generic probabilistic risk assessment study identified the important systems, components, and activities that could contribute significantly to core melt accident sequences or mitigate the consequences of such events.

The inspection team concluded that Fort Calhoun Station emergency operating procedures (EOPs), when used by experienced and trained operators, provided adequate direction to mitigate the consequences of an accident. The risk-important systems and components are generally tested and maintained commensurate with their importance to risk. This provides reasonable assurance of system/component availability for accident mitigation.

Two violations (one of which was not cited), one deviation, and three inspector followup items were identified during this inspection. The violations involved: (1) inadequate emergency operating procedures and abnormal operating procedures; and (2) a licensee identified failure to have an adequate design control program for electrical circuit fuses. The deviation involved a failure to conduct an EOP validation as committed to in the submittal to the NRC dated March 1, 1985. The three inspector followup items concerned: (1) the lack of a fuse/breaker coordination study; (2) the lack of a fuse control program; and, (3) the lack of performance of a stroke test for the power-operated relief valves (PORVs).

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EXECUTIVE SUMMARY

During the period October 23 through November 9, 1989, a team inspection was conducted to evaluate the risk-based operational safety and performance assessment at the Fort Calhoun Station (FCS). Since the FCS does not have a site-specific probabilistic risk assessment (PRA) study, a generic PRA-based methodology was developed. This inspection was conducted to apply the generic methodology at FCS in order to evaluate the availability of important systems and components and the success of operator actions to prevent reactor core damage. The inspection was conducted in accordance with the guidelines of Inspection Procedure 93804, "Risk-Based Operational Safety and Performance Assessment."

The inspection team concluded that the activities, systems, and components important to mitigate the consequence of a core melt accident were satisfactory at FCS; however, the following weaknesses were identified:

1. Multiple examples of inadequacies were identified in abnormal and emergency operating procedures.

2. The validation of emergency operating procedures was not completed in accordance with the licensee's commitment to the NRC in a letter dated March 1, 1985.

3. There was no fuse/breaker coordination study for the 480 volt AC, 120 volt AC, and 125 volt DC buses.

4. The lack of a fuse control program was noted. The FCS does not have a fuse control program to ensure that the correct fuses are installed. The design documents do not provide sufficient information to determine the proper type of fuse to be installed, and the program for procurement of fuses does not assure correct fuses will be procured.

5. The FCS power-operated relief valves were not being stroke-tested as part of the inservice testing program (IST). The licensee made a commitment in Revision 3 of IST program to stroke-test these valves. However, this program revision will not be fully implemented until the end of the 1990 refueling outage.

The inspection team also identified the following strengths of the licensee's program:

1. Discussions with the licensee's PRA staff revealed that OPPD will have a comprehensive PRA program when completed.

2. The licensee's monitoring system to detect the intersystem LOCA was considered effective.

3. General housekeeping was considered to be excellent.

INSPECTION DETAILS

1. SCOPE OF INSPECTION

A probabilistic team inspection was conducted to apply the generic inspection methodology that is based on probabilistic risk assessment (PRA) insights at the Fort Calhoun Station (FCS). The objectives of the inspection were to evaluate the availability of the systems and components important to mitigate an accident, and to evaluate the ability of operator actions to prevent reactor core damage. The generic methodology used focused on core damage with one exception. The interfacing system loss-of-coolant accident (LOCA) sequence was also included due to the potential offsite consequences of such an event.

Eleven representative pressurized-water reactor (PWR) accident sequences have been developed. Each representative accident sequence and the associated PRA-based events were reviewed to determine relevance to FCS. The result was a list of 11 dominant accident sequences and multiple combinations of component failures and human actions that can lead to core damage at FCS.

The 11 generic accident sequences were ranked on the basis of relative risk in accordance with Fort Calhoun's design. The 7 sequences of major concern are listed below:

- Small or medium LOCAs with failure of high-pressure injection or recirculation;
- Interfacing systems LOCA;
- Loss of 125 volt DC bus with failure of the auxiliary feedwater system (AFW);
- Loss of offsite power with failure of AFW and feed and bleed;
- Station blackout with loss of the AFW system;
- Loss of power conversion system (PCS) (or a general transient with loss of PCS) followed by loss of AFW; and
- A transient with failure to automatically and manually scram the reactor with failure of timely emergency boration.

Each accident sequence is composed of an initiator with subsequent system failures that ultimately lead to core damage. Similarly, each critical system has multiple combinations of component failures and human errors (or basic events) that can disable it. Each of these basic events can be ranked using an importance calculation, which is a relative measure in terms of prevention, mitigation, or recovery from core damage sequences.

The estimated system importance ranking at Fort Calhoun is given below:

System	Importance Estimate
Auxiliary feedwater	very high
Emergency power, AC and DC, including vital buses/inverters	very high
High-pressure safety injection (including recirculation mode)	high
Once-through cooling (PORVs, block valves)	high
Low-pressure injection	medium
Room cooling	medium
Safety injection and refueling water tank	medium
Safeguards actuation logic	medium
Closed cooling water	medium
Raw water	medium

The inspection scope was modified to account for recent station experience. For example, the review of maintenance activities was de-emphasized because of the recent NRC maintenance team inspection. Since the emergency diesel generators (EDGs) have been the subject of much scrutiny, they were given a lower inspection priority, with the exception of potential common-cause failures.

Although the instrument air system is generally not addressed in plant PRAs, it can impact safety-related components. Because Fort Calhoun has a large number of safety-related air-operated equipment (1200 components), the system was examined during this inspection.

The Fort Calhoun water chemistry program, which is also normally outside the scope of the PRA, was reviewed.

Four of the activities that ensure system and component availability were examined. These are briefly described below:

- Accurate surveillances - to ensure the system or component is tested in a manner that approaches an actual system demand;
- Timely surveillances - to ensure prompt detection of failures;
- Prompt maintenance activities - to minimize component unavailability; and,

- Prevention of failures, including trending programs and root-cause analysis, to maintain availability of systems and components.

Human actions were addressed in the specific areas described below:

- Training - to confirm the operator has received adequate training to address high-risk sequences;

- Human factors - to minimize the potential for human error;

- Procedure adequacy - to confirm that the operator has clear guidance; and,

- Control room simulations - to review operator response to selected risk significant accident sequences.

2. ASSESSMENT OF EMERGENCY OPERATING AND ABNORMAL OPERATING PROCEDURES

The inspectors interviewed licensed operators in the control room to assess the effectiveness of the emergency operating procedures (EOPs) and an abnormal operating procedure (AOP). The inspectors also evaluated the knowledge of the operators to detect and mitigate a LOCA in a system located outside the containment that interfaces with the reactor coolant system (RCS). During these interviews, procedures were walked down, Technical Specifications (TS) interpreted, and specific equipment operability determined.

2.1 Operator Performance With AOP Usage

The inspectors walked down AOP-17, "Loss of Instrument Air," Revision 13, for all portions performed in the control room, with a licensed operator. During the walkdown, decreasing instrument air (IA) pressure was simulated with no other event or transient in progress. The operator was provided cues to represent changing plant conditions and was asked to interpret various steps, notes, and cautions. The following procedural inadequacies were observed during this effort:

- AOP-17 instructs the operations staff to control feedwater flow using the feedwater regulating bypass valves through the alternate auxiliary feedwater injection path. However, the auxiliary feedwater injection valves (normal flow path) fail open on a loss of IA system pressure. Therefore, while the operator is establishing flow control with the main feedwater regulating bypass valves, the steam generators (SGs) continue to be filled through the normal flow path. This procedural inconsistency represents a potential for initiation of an overcooling event.

- If IA system pressure is lost, the pressurizer spray valves fail closed. AOP-17 notes that RCS pressure control may be difficult, but the procedure does not provide information about the alternate method available for pressurizer pressure control (i.e., use of a charging pump through solenoid-operated Valve HCV-249). This lack of procedural information could lead to a potential overpressurization event and unnecessary challenges to the pressurizer relief and safety valves.

TS 5.8.1 requires the licensee to have adequate AOPs. The procedural problems discussed above represent inadequacies with Procedure AOP-17 and are considered to be an apparent violation of TS 5.8.1.

Violation (285/8940-01): Failure to have adequate procedures to mitigate transient plant conditions.

In response to the procedural problem with regard to initiation of an overcooling event, the licensee revised Procedure AOP-17 to specify the correct method for feeding the SGs if IA system pressure is lost. The licensee had not addressed the problem of providing information in Procedure AOP-17 regarding the method for pressurizer pressure control on loss of IA system pressure by the conclusion of the inspection.

These inadequacies only represented a portion of the observations made during the execution of the walkdown of AOP-17. The following additional problems were identified:

- No summary sheet was provided for what happens to the valves in containment when IA system pressure is lost. Summary sheets were provided for valves in other plant areas. Containment summary sheets would provide a good reference for operations personnel.

- Step 3.1.7 states that if air pressure returns to normal, refer to Attachments 1 and 4 for the failure mode of valves located in containment. This step does not provide operators with specific actions to take. Some valves in Attachment 1 do not have position indication in the control room; therefore, it is not apparent how the operator can verify the failure mode position.

- A note in Procedure AOP-17 states that raw water/component cooling water (RW/CCW) interface valves to and from the shutdown cooling heat exchangers, safety-injection and containment spray pumps, and containment and control room air handling units, are equipped with accumulators designed to hold valves closed for 2 hours. As a precaution, these valves should be hand-jacked closed. A list of the appropriate valves was not provided in the procedure.

  In addition, Valve HCV-2812C (a RW/CCW interface valve) could not be shut because of interference between a pipe and the handwheel. When the inspectors notified the licensee of this observation, the licensee removed the handwheel on Valve HCV-2812C and replaced it with a ratchet wrench, which allowed the valve to be hand-jacked closed as directed by the procedure.

- Attachment 4, "Air-Operated Valves with Accumulators," provides the expected length of time a valve will be operable after a loss of IA pressure. For 16 RW/CCW interface valves listed in the attachment, the procedure states that the valves will remain operable for 2 hours. The accumulator assemblies for the valves were tested after the initial installation in approximately 1972 and have not been tested since; therefore, it is not apparent how the 2-hour time was established.

- Step 3.2.10 implies that any containment isolation valve not in its fail safe position shall be manually operated to establish containment integrity. This may require a containment entry when undesirable. The licensee should review this step to determine the actions that operations personnel should be performing.

- Although the procedure states that the operator may manually block air-operated valves in a position other than their fail safe position, the inspectors could not determine how valves that failed shut, could be manually blocked in the open position.

The licensee has performed a review of the concerns listed above. A change to Procedure AOP-17 was made to address the concerns.

2.2 Operator Performance With EOP Usage

The inspectors developed two scenarios to be used to evaluate: (1) the ability of control room operators to exercise the EOPs, and (2) the effectiveness of the EOPs. The specific accident sequences were selected on the basis of their applicability to FCS and generic PRA insights for PWR plants. The first scenario used a station blackout as the initiator with failure of the AFWS system. The second scenario used a loss of offsite power as the initiator with a subsequent loss of all feedwater. Both of these sequences have an enhanced applicability to FCS because of the high estimates for failures of various safety-related equipment and systems. The scenarios were walked down in the control room with an off-duty operations crew. These walkdowns encompassed the following EOPs:

- Em[illegible] Operating Procedure (EOP)-00, "Standard Post Trip Actions," Re[illegible];

- EOP-[illegible] Loss of Offsite Power/Loss of Forced Circulation," Revision 6;

- EOP-06, "Loss of All Feedwater," Revision 4;

- EOP-07, "Station Blackout," Revision 0; and

- EOP-20, "Functional Recovery Procedure," Revision 6.

The inspectors initiated the problems by providing the operators with initiating cues to depict plant conditions. Subsequent cues were provided to the operators depending on their individual and collective actions. With this methodology, it was not possible to assess operator performance or effectiveness in taking actions required within critical time restraints. The inspector observed these scenarios and was able to provide insight as to how operator performance and procedures affected risk.

As the result of the execution of these scenarios, the following procedure inadequacies were identified:

- Step 3.6.d of EOP-02, "Loss of Offsite Power/Loss of Forced Circulation," does not address the need to augment the cooling water for the air compressors if turbine plant cooling water is not available. (Insufficient cooling water could result in overheating and subsequent loss of the air compressors.)

- Steps 3.8 and 3.9 of EOP-02 do not provide instructions for the control room operator to ensure that the radiator exhaust dampers open for emergency diesel generators 1 and 2. (Failure of the dampers to open would result in overheating and subsequent loss of the diesel generators.)

- EOP-06, Step 3.11, Contingency Action states: "Immediately Initiate Once Through Cooling if both steam generators (SGs) are less than 20% (wide range) and RCS temperature is increasing." This step was inserted into the procedure as a result of the safety evaluation report for Generic Issue 124, "Resolution of Generic Issue 124, Auxiliary Feedwater System Reliability, for Fort Calhoun," dated May 9, 1988. As previously pointed out, there is an urgency to initiate once-through cooling early in a transient to ensure it will be successful. The only place in the procedure that this urgency is communicated to the operator is in Step 3.11 of EOP-06. There are numerous situations that could occur in which the operator would exit the procedure before reaching this step. For example, EOP-06, Step 3.2.c, directs the operator to EOP-20. The licensee needs to review the EOPs to ensure that this urgency is repeated throughout the EOPs so that it can be communicated to the operator when necessary.

- EOP-20, Resource Tree E, page 30, indicates that once-through cooling will be successful if there is one operating high-pressure safety injection (HPSI) pump and RCS pressure is less that 1350 psia. Step 6.8 of the safety function status check for core and RCS heat removal does not designate the number of HPSI pumps needed to meet the success criteria. A caution on the first page of HR-4, the procedure for once-through cooling, states that successful heat removal using once-through cooling requires both power-operated relief valves (PORVs) and at least two HPSI pumps. The caution statement directly conflicts with the requirements found in the resource tree and the safety function status check. Further, if this caution statement is accurate, it may not be seen by the operator for several minutes while he is performing instructions for all safety function success paths in use.

The procedural problems discussed above represent inadequacies with the EOPs and are considered to be part of the apparent violation of TS 5.8.1 identified in paragraph 2.1 of this report.

These inadequacies only represented a portion of the observations made during the preparation and execution of these scenarios. The following additional problems were identified:

- EOP-00, Step 3.7, did not explain how to verify that the numbers 1 and 2 DC buses were energized. The crew pointed out two different methods to determine that the buses were energized but did not know what constituted a satisfactory verification.

- EOP-00, Step 3.13, directed the operator to verify conditions associated with the SGs; Substeps c and d required the operator to take specific actions. Action steps should not be hidden.

- EOP-00 required the operator to verify that one of the component cooling water (CCW) pumps was operating at greater than 60 psig discharge pressure. However, the safety function status check (SFSC) for EOP-02, "Maintenance of Vital Auxiliaries (MVA)," required that two CCW pumps be in operation. The purpose of EOP-00 is to ensure that all SFSCs are satisfied. Therefore, the requirements of steps in EOP-00 and an SFSC should be identical.

- Licensee personnel informed the inspectors that the use of EOP resource trees and flow chart diagnosis was not a requirement. Step 3.16 of EOP-00 instructs the operator to enter EOP-01 for a normal reactor trip recovery or provides contingency action directing the operator to the diagnostic action flow chart. There are no procedure steps that allow the operator to directly access one of the event-specific EOPs or EOP-20 (Functional Recovery) without transition through the diagnostic action flow chart.

- The format of the EOPs requires EOP-00 to be completed prior to entering subsequent EOPs. In the event of a loss of feedwater, the operator is not instructed to isolate SG blowdown until Step 3.10 of EOP-06. Since EOP-06 is not performed until after EOP-00 is completed, this results in an extended inventory blowdown of the SGs. In addition, EOP-00 and EOP-06 have a number of "exit" points prior to the operator reading Step 3.10. Therefore the possibility exists that the operator may not isolate the SG blowdown resulting in a considerably reduced heat removal capacity of the SGs.

- The operators demonstrated a decided unfamiliarity with the heat removal capability of the steam generator (SG) inventory after the occurrence of a loss of all feedwater. When asked about their estimate of elapsed time before SG inventory would be exhausted after a reactor trip with no feedwater available, answers ranged between 1 and 2 hours. A lack of operator knowledge about SG inventory--hence, loss of heat removal ability which may be exhausted within 20 minutes after reactor trip--could be a major contributing factor to core damage. Once-through cooling should be initiated before SG inventory is exhausted if it is to be effective. The validity of the need for timely initiation of once-through cooling is supported by the CE Report, "Engineering Evaluation of Feed and Bleed for Total Loss of Feedwater Events at Fort Calhoun Station," dated December 1988.

- The entire three-member operating crew demonstrated a strong reluctance to enter EOP-20, the functional recovery procedure. Entry into this procedure is required when there is not apparent event diagnosis, the correct guidance cannot be identified, actions are not satisfying the acceptance criteria for the optimal safety function status check, or plant conditions indicate that two or more events are occurring simultaneously. During the initial scenario, the operators collectively exhausted every path before they would consider entry into EOP-20. During the second scenario with only one essential bus being energized by a diesel, simultaneous with a loss of all feedwater, one operator rationalized that it was not necessary to enter EOP-20 because, if the loss of power could be solved, the loss of feedwater would be solved and would no longer be a concern. When the inspectors asked the operators about their reluctance to enter EOP-20, one operator alluded to the sheer volume or size of the procedure.

- The steps to restore full once-through cooling from partial cooling in EOP-20 (15.97 - 15.105 and 15.107 - 15.114) should be expedited because partial once-through cooling does not meet the heat removal success criteria. It is necessary to complete these steps quickly to preclude greater risks of core damage.

- EOP-20, Steps 15.99 and 15.108, provide breaker identification numbers for components that should be identified as buses.

- At the time of the inspection, formal training of licensed operators had been completed on only EOPs -06, -07, and -20. Final review of all training lesson plans used to familiarize the operators with the revised EOPs was not complete. More training was needed to address the operators' lack of knowledge on the execution of EOP-20.

2.3 General Performance Observations

In addition to the AOP and EOP performance problems discussed in paragraphs 2.1 and 2.2 of this report, the following general observations were made by the inspectors during procedure walkdowns and scenario executions:

- The operators are not provided clear instructions to assess the emergency core cooling system (ECCS) check valve leakage. Assessing total valve leakage from all four loop injection points is a simple process of reading a flowmeter. However, Table 2-9 in the Technical Specifications provides limits for individual valves and does not address total valve leakage. The operator stated that he knew of no method to quantify individual valve leakage if it was suspected that leakage was occurring through more than one check valve. He also stated that he was not sure when the limiting condition of operation (LCO) on ECCS due to inoperable piping and valves should be entered. Subsequent to this interview the inspectors determined that the LCO would be entered before any one valve had significant leakage and that individual valve leakages are verified during outage period testing.

- At the time of the inspection, there was no documentation located in the control room from which to determine plant relief valve set points. The operator being interviewed and the on-shift operators could not determine the set points for two relief valves (SI-187 and SI-222).

- Step 3.14 of EOP-03, "Loss of Coolant Accident," provided instructions to determine if a LOCA had occurred inside containment. Contingency action then required the operator to determine if the leak was in the RCS's sample system, the chemical and volume control system (CVCS) letdown line, or the shutdown cooling system. The low-pressure safety injection system (LPSI) was not addressed because this system is normally isolated from the RCS by two check valves and a closed motor-operated isolation valve to minimize any chance of this low-pressure piping being exposed to RCS pressure. Risk of a LOCA occurring outside the containment via the LPSI system is further reduced by a relief valve (SI-187) located inside the containment and discharging to the pressurizer quench tank. The operator being interviewed was readily able to determine LPSI header pressure and pointed out how the header relief valve would limit header pressure increase from leakage within the system. The inspectors concluded that a LOCA that would effectively bypass the containment barrier was not a significant risk at FCS.

2.4 EOP Validation

The NRC informed the licensee by letter dated October 5, 1989, that the licensee's proposed validation plan for revised EOPs needed to be strengthened. However, because of the date of the NRC response, the more stringent requirements for the validation program were not assessed during this inspection. This inspection assessed conformance with the validation program originally submitted in the licensee's proposed procedure generation package (PGP) by letter dated March 1, 1985.

Part 5, paragraph 5.0, of this PGP states that "the initial EOP/AOP validation process shall consist of Control Room walk-throughs utilizing the Fort Calhoun Control Room Mock-Up." However, the licensee could not provide documentation to show that this effort was undertaken and completed. Licensee personnel stated that they believed this requirement only applied to the two new EOPs (07 and 20) because they are the only EOPs that are "technically different" from the EOPs in effect before the revision of July 31, 1989. The inspectors informed the licensee that all EOPs currently in effect are required to be validated in accordance with the licensee's commitment specified in the PGP submittal letter and that documentation is required to support this validation.

This discrepancy in the licensee's EOP validation process is an apparent deviation from the licensee's commitment to validate the EOPs in accordance with the PGP submitted to the NRC for review.

Deviation (285/8940-02): Failure to perform EOP validations in accordance with the PGP as committed to the NRC.

In addition to this deviation from a commitment, the inspectors made the following observations with respect to the procedure validation process:

- The EOP validation documentation consisted of scenarios designed to exercise the EOPs with various attachments from Part 5 (Validation

Program) of the PGP. However, there was nothing to indicate if the validation had been performed using the simulator, walkdown, tabletop, or reference method. The licensee stated that all validation for control room steps had been performed on the Combustion Engineering (CE) simulator located in Windsor, Connecticut, and that all local action steps had been validated by plant walkdown. In this case, the documentation did not describe how the simulator process provided adequate validation considering the significant differences between the FCS control room and the CE simulator. Further, since there was no documentation to support validation of local action steps by walkdown in the plant, the inspector concluded that this validation had not been accomplished.

- Attachment 4 to the PGP, Part 5, is a form used to resolve discrepancies discovered during the validation process. The licensee stated that procedure discrepancies were discovered by several individuals during the validation process. A review of approximately 50 of these discrepancies indicates that only two contractor personnel reported discrepancies. Further review confirms that in every case where a discrepancy was reported, the resolution was approved by the same individual finding the discrepancy. There is no documentation to indicate an independent review of approved resolutions.

2.5 Conclusions

From a PRA perspective, the above examples of procedural inadequacies and operator training deficiencies are cause for concern. Because of this concern, the inspectors questioned the ability of an inexperienced operator to mitigate a serious plant challenge. Since the present facility staff consists of experienced operators, the inspectors considered the present procedures to be adequate for present operations. Improvement to the procedures will be monitored as part of the NRC followup to the apparent violation discussed above.

The procedural inadequacies can impact both frequency of occurrence and system availability. For example, the lack of guidance in AOP-17 for RCS pressure control after a loss of instrument air could result in an overpressurization event. The increased challenges to the pressurizer relief and safety valves probabilistically increase the chances of a stuck open valve, which is a contributor to the small LOCA.

The inspection revealed strengths and weaknesses associated with the human factors aspects of AOPs and EOPs at the FCS. The two-column format was considered a strength because of the direction that was provided to complete the step. Another strength was noted in the draft lesson plans being developed to teach the operators and operator license candidates how to use the procedures. These lesson plans should provide the student with a flow chart to illustrate individual steps within the procedure. The training department is enthusiastic about developing effective training material to improve the operator's knowledge and enhance procedure usage. The individual EOPs are kept in separate identifiable binders in the control room, readily available to the operators. The licensee plans to convert AOPs into the same two-column format, which should improve these documents.

In addition to the weaknesses presented earlier in this report, another weakness was that there is no consistency for use of the procedural requirement to "monitor the floating steps." This phrase appears at the beginning of each EOP and is randomly inserted throughout the EOPs. The licensee could not explain the criteria used to place this step within a procedure. Further, it appeared to the inspectors that at any given point during the exercise of the EOPs, several "Floating Steps" should not be monitored, but ignored.

3. AUXILIARY FEEDWATER SYSTEM

3.1 Components of the Auxiliary Feedwater System (AFWS) and Their Availability

The inspectors reviewed factors, such as inservice testing (IST), maintenance history, and surveillance testing, that affect the reliability of key components of the AFWS. They also reviewed: (1) the adequacy of test proceduresto ensure that testing provided meaningful results, (2) test history to verify that tests were conducted regularly to maintain confidence in equipment operability and to meet requirements of the Technical Specifications (TS), and (3) equipment maintenance history to identify continuing problems. Finally, the NRC evaluations of the AFWS were reviewed. The results of the reviews are discussed below:

° The review of the maintenance records for motor-driven AFWS Pump FW-6 did not reveal any new problems. The inservice testing/surveillance testing problems identified in NRC Inspection Report 50-285/89-27 were the subject of pending escalated enforcement actions. The licensee had committed to adding a third AFWS pump during the 1990 refueling outage, as a result of the NRC AFWS reliability study. The licensee also plans to install a new header which will allow full-flow testing of AFWS pumps while the plant is on-line.

° The inspectors reviewed the system operating procedures and walked down the AFWS to verify correct system alignment for current plant conditions (100 percent power). In the procedure review, the inspectors noted one format problem. The system alignment checklist, FW-4-CL-A, in Procedure OI-FW-4, Revision 42, dated July 27, 1989, was numbered as "page ___ of eight." Actually, the checklist was 11 pages long. When the licensee was informed of this discrepancy, the checklist was corrected so that the correct number of pages were listed. Although this was not a significant safety issue, it did indicate poor administrative control of procedures.

° System alignment was correct for plant conditions and the auxiliary feedwater spaces looked very good from a housekeeping perspective. However, the inspectors noted deficiency tags on the AFWS turbine steam inlet valve (YCV-1045) and on the turbine throttle valve because of excessive leakage. The leaking valves allow steam to migrate into the turbine casing where steam trap (ST)-16 is the only component available to ensure that the condensate is drained out of the turbine. Condensate accumulation in the turbine has been shown to be a contributor to AFWS pump turbine failures to start (NRC Information Notice 88-09). The licensee was asked if compensating measures had been implemented to ensure that the turbine would operate on demand. The licensee subsequently revised the turbine building log (Form FC-78, Revision 31) to check the proper operation of the steam trap.

° During a review of the AFWS documentation, a discrepancy was noted in the normal position of the turbine steam inlet Valves YCV-1045, -1045A, and -1045B and AFWS containment isolation Valves HCV-1107A, -1107B, -1108A, and -1108B. The applicable flow diagrams (11405-405-M252, Revision 55, and 11405-405-M253, Revision 67) show all valves normally closed. However, the licensed operator training program materials for the AFW system (Lesson Plan 7-11-1, Revision 2, dated September 11, 1989, transparency index and student handbook) show these valves normally open. The licensee has corrected the licensed operator training lesson; the corrective action taken by the licensee is acceptable.

3.2 Conclusions

As previously discussed in Section 1, the FCS AFWS is an especially important system from a core damage perspective. The failure of AFWS is a contributor to four of the seven accident sequences that are considered risk important for FCS. The inspection effort was commensurate with the system risk importance.

The AFWS pumps (FW-6 and -10) are key system components and were examined in-depth, including surveillance, inservice testing, and maintenance practices. The availability of each pump was calculated and noted to be approximately the industry norm. Selected system valves were also examined in a similar manner. On the basis of these observations, the inspectors determined that the licensee is treating the AFWS commensurate with its risk importance to FCS. The team did not note any outstanding concerns that could significantly change the estimated AFWS availability identified in the generic methodology.

4. ELECTRICAL SYSTEM

4.1 Availability of Electrical Components

The inspectors reviewed the availability of the PRA driven electrical systems and components. A common-mode concern for all components associated with the PRA is the lack of coordination between the electrical fuses, circuit breakers, and relays. This was expressed as a "common bus" concern in the fire protection reviews conducted to ensure compliance with 10 CFR Part 50, Appendix R. The basic concern is that an electrical fault will cause an upstream breaker, fuse, or relay to trip or open before the protection unit serving the faulted component actuates or trips. This could result in a power loss to redundant components. The inspectors requested a coordination study for the components associated with the PRA, but the complete information was not provided by the time of the exit interview. A review of the provided coordination curves disclosed the following shortcomings, which should be addressed as a part of the fuse coordination corrective action program:

- Coordination information should be developed for the control fuses for Valves YCV-1045A/B, HCV-1107A/B, HCV-1108A/B, HCV-383-3, and HCV-383-4; Block Valves HCV-150 and HCV-151; PORVs PCV-102-1 and -102-2; and controls for AFW automatic initiation.

- Written conformation should be provided which verifies that the short circuit current for Circuit Breaker ITE-JI2-T400 (feed for 125 volt DC bus No. 2) is limited to 450 amps. This will satisfy the coordination overlap of Curves 2 and 3 on the coordination sheet dated October 30, 1989.

- An explanation of the apparent lack of coordination between the input and output circuit breakers on Battery Charger 2 should be developed. The lack of coordination is shown on coordination Curves 4 and 5.

Discussions with licensee personnel indicated that the fuse/breaker coordination problem is already a part of the FCS safety enhancement program (SEP). Licensee progress in this area will be reviewed during future inspections and is considered to be an Inspector Followup Item.

Inspector Followup Item (285/8940-03): Review resolution of the electrical breaker/fuse coordination problem.

Another common-cause concern that could affect almost all of the PRA driven electrical components is the lack of a comprehensive fusing program, which interfaces with the coordination concern on circuit breakers, relays, and fuses discussed above. A comprehensive fusing program should include:

- A master fuse list for safety-related systems that would state the size and type of fuses and that reflects the correct engineering design of all the safety-related circuits;

- A means of labeling the fuses in the field so that the craftsmen replacing the fuses would have clear labels to follow;

- Documentation of the proper fuse and relay/circuit breaker coordination; and

- A means of updating and correcting installation and maintenance work orders that bring about changes in fuse sizes and types.

The need for such a program was determined when auxiliary feed control Panel AI-179 was examined and compared with OPPD Print 161F593, Revision 12. The inspectors noted that: (1) many fuse sizes could not be determined; and (2) 5-amp fuses were installed at fuse blocks F-21 and -22 in place of 1-amp fuses as required by the print. These fuses are for a preamplifier used in the reactor protection system. The inspectors verified that several other PRA driven component fuses were the correct size, but were unable to verify the correct design type because of the lack of a comprehensive fuse program. This item had previously been identified by the licensee and therefore has been determined to be a licensee-identified violation. The licensee committed to develop an interim (short term) fuse control program within 5 days of the end of this inspection and to develop a comprehensive fuse control program by the end of the spring 1990 refueling outage. The interim program provides that electrical/craft personnel will be notified by a memorandum to replace any defective fuse with the same type of fuse. Also procedures will be issued that will require an engineering evaluation whenever fuse replacement is required. This interim corrective action was found to be acceptable by the inspectors. Based upon these corrective actions taken by the licensee and in accordance with the revised enforcement policy, a Notice of Violation is not being issued.

The NRC will review implementation of this program during future inspections. Inspector Followup Item (285/8940-05): Review implementation of the electrical fuse control program.

The inspectors considered the electrical common-cause failure of the two diesel generators. The inspectors reviewed the Fire Hazard Analysis, Revision 3, dated September 1988, for Fire Area 35 A/B, and discussed the availability of the emergency AC power system with the plant fire protection engineer. When offsite power is lost and the control room evacuated, the diesel generators can be controlled locally at their local control cabinets. Each of these cabinets has a normal and an emergency feed. Although the inspectors were not concerned about an electrical common-mode failure, the general concerns discussed above apply to the fusing and circuit breakers of the diesel generator control circuits.

The reliability of the vital buses and their associated power inverters encompasses almost the entire electrical system. The inspectors were therefore, concerned over the lack of an overall preventive maintenance program or comprehensive surveillance test procedure for the Class 1E inverters. New inverters and battery chargers were installed in 1985, and certain limited maintenance procedures were written, e.g., MP-EE-16A-R1, dated May 26, 1987, provides for the replacement of capacitors every 9 years. The inspectors reviewed a draft copy of a preventive maintenance procedure for the Class 1E inverters, EM-PM-EA-0800, and found it to be acceptable. Implementation of this PM is an Inspector Follow Item (285/8940-04).

The inspectors reviewed failure information for the 120 volt AC inverter. In 6 of the 11 failures described, a fuse had blown. A September 2, 1988, memorandum (PED-FC-88-510), established that in the case of 8 failures of Class 1E inverters, 7 failures involved a blown fuse. The licensee was unable to verify to the inspectors if the correct size of fuse has been replaced. These examples emphasize the importance of the protection provided by the correct size and type of fuse.

4.2 Conclusions

The lack of a fuse control program and a comprehensive breaker/fuse/relay coordination study and the inverter concerns previously cited are considered to be important sources of common-mode failures. These concerns could affect all of the accident sequences used for this inspection. The lack of a fuse control program or an incomplete breaker/fuse/relay coordination study can have severe consequences. For example, a critical component could fail randomly on demand (e.g., a locked pump rotor), and instead of actuating the local protective device, an uncoordinated electrical system (or an improper fuse) could result in the actuation of an upstream protective device. This could disable additional critical components.

Similarly, several important FCS accident sequences postulate losses of electrical power. The concerns expressed above could potentially increase the probability of a loss of a DC bus as well as a station blackout resulting from the loss of an AC bus.

5. INSTRUMENT AIR (IA) SYSTEM

The failure of the IA system was identified as a major contributing factor to the potential for a significant accident because of the large number of valves and components installed in the safety-related systems that use the IA system. Operation of the valves and components during accident conditions is mandatory for the mitigation of accidents and for preventing plant perturbations from resulting in more severe accident scenarios. For this reason, maintaining the stability of the IA system represents a high concern with respect to safe plant operation.

In evaluating the operation of the IA system, two major vulnerabilities were considered: the loss of IA system pressure and the inadvertent introduction of water into the system. The occurrence of either problem has the potential of significantly affecting the operation of the valves and components supplied by the system.

5.1 Loss of IA System Pressure

The loss of IA system pressure was considered on the basis of all potential initiating events such as loss of power to the air compressors or a major line break in the system. It was assumed that the IA pressure was lost as the motive force to air-operated valves or as the operational source for components such as level indicators and controllers.

The inspectors reviewed the licensee's documentation of specific valves that are designed to fail in the safe position should air pressure be lost. This review included the licensee's Operations Support Analysis Report (OSAR) 87-10 and Preventive Maintenance Procedure PM-REG-1. On the basis of the reviews, it appeared that the licensee had taken the appropriate actions to address the availability of the IA system to mitigate the consequences of an accident.

5.2 Water Intrusion into the IA System

In addition to the loss of IA system pressure, the intrusion of water into the system could adversely affect the operability of valves and components because they are designed to operate using dry, clean air. The inspectors reviewed the actions taken by the licensee to prevent entry of water, and to detect the presence of water in the IA system, and found them acceptable.

In July 1987 the licensee experienced an event where water entered the IA system causing the status of the system to be indeterminate. As the result of this event, one of the licensee's corrective actions was to blowdown the accumulators for the emergency diesel generator exhaust dampers (YCV-871E and YCV-871F) quarterly to verify that no water was in the accumulator. The blowdowns were accomplished in accordance with Preventive Maintenance Procedures PM-DAMP-1 and PM-DAMP-2. This corrective action was a commitment made in response to a Notice of Violation and Proposed Imposition of Civil Penalty documented in NRC Inspection Report 50-285/87-27.

During the 1988 outage, the licensee replaced the air-operated actuators for YCV-871E and YCV-871F with actuators that did not have accumulators. In an internal memorandum dated January 8, 1989, the licensee cancelled Procedures PM-DAMP-1 and PM-DAMP-2 as they were no longer required since the newly installed actuators did not have accumulators. It appears that the licensee's replacement of the actuators did not introduce additional vulnerabilities into the IA system.

5.3 Conclusions

Overall, the IA system appeared to be well maintained and an appropriate level of testing was being conducted for early identification of adverse system trends. If the licensee continues its current program designed specifically to address the availability of the IA system, it is anticipated that the system will perform reliably.

6. SAFETY INJECTION SYSTEM

6.1 Availability of the Safety Injection System (SIS) Pumps

The failure of the miniflow system to provide sufficient recirculation flow to prevent safety injection pump damage was considered a contributor to a failure of high-pressure injection during a small or medium LOCA. The PRA concern is the potential common-cause failure of all operating pumps. In a draft response to NRC Bulletin 88-04 (PED-FC-88-1355, dated December 27, 1988), the licensee committed to change the containment spray (CS) pump actuation logic to alleviate the concern that the miniflow configuration was not sized to allow sufficient recirculation flow with all pumps running (Combustion Engineering letter, OPPD-88-170 dated December 22, 1988). This change modified the CS pump actuation logic such that these pumps would not start until a high containment pressure signal was available. If this condition occurred and the CS pumps start, they will not operate in the recirculation mode because containment spray will be in full operation.

Following implementation of this modification to the CS pump actuation logic, a test involving the simultaneous startup of high pressure safety injection/low pressure safety injection (HPSI/LPSI) upon receipt of a safety injection actuation signal was conducted. This test was run for 45 minutes. Since the CS pumps did not start during this test (due to the lack of a high containment pressure signal) the miniflow system provided adequate recirculation flow. In addition, the existing plant accident analyses and the emergency and abnormal operating procedures provide assurance that the HPSI and LPSI pumps will not operate in the simultaneous minimum recirculation mode for more than 30 minutes. Based upon the test results and the administrative control of these pumps, the inspectors found SIS pump availability to be acceptable.

The containment sump recirculation Valves HCV-383-3 and HCV-383-4, were not accessible for direct observation with the plant on-line. These valves are located inside an extension of containment that protrudes into the auxiliary building. However, the inspectors reviewed the maintenance and testing records of these valves and did not identify any concerns. With regard to the availability of the containment sump recirculation system, the inspectors reviewed the postulated failure mode which could cause the valves to fail to open. These recirculation valves are motor-operated valves with open and close limit switches for remote indication. The inspectors reviewed eight Maintenance Orders (MOs) relating to these valves, surveillance test ST-SI/CS-1 performed in May 1987, and the equipment qualification documentation forms, Revision 4, dated October 5, 1987, for quality-related problems. The inspectors did not identify concerns during these reviews.

The inspectors examined LPSI pumps, SI-1A and SI-1B, and the general area of the pump rooms. The pumps appeared clean and well maintained, and housekeeping in the pump rooms was excellent. A review of maintenance records produced no inspector concerns. A review of testing records, however, revealed that these pumps are tested with the same procedure and same technique as the HPSI pumps. This is a minimum recirculation flow test. The testing of the high-pressure pumps is the subject of Unresolved Item 285/8901-01 identified during the maintenance team inspection (NRC Inspection Report 50-285/89-01). This concern is also applicable to the LPSI pumps. This item will be evaluated further during the inspection followup for NRC Inspection Report 50-285/89-01.

The inspector examined the component cooling water Pumps AC-3A, B, and C and found housekeeping in the general areas satisfactory. A review of maintenance and testing records produced no inspector concerns. The test procedure satisfactorily tested the pumps and measured appropriate parameters, including discharge pressure, flow rate, and bearing vibration. Records of completed tests indicated satisfactory pump performance.

With regard to pump room cooling, the inspectors also reviewed the postulated failure of the electrical supply feed and circuit breaker to the safety injection (SI) system that ventilates the SI pump room. Drawing 11405-M-2, Sheets 2 and 3, show that Fans VA-40A, B, and C cool the SI pump rooms and other large sections of the auxiliary building. The licensee stated that this ventilation system could be completely lost without any loss of safe shutdown ability. This position was supported by a Combustion Engineering Company study, dated July 19, 1979, that showed that pump room temperature without the fans is 117°F, which is 5°F below the upper temperature limit for pump room operation. This study was found to be acceptable.

6.2 Conclusions

The SIS consists of the HPSI and LPSI subsystems. The HPSI provides emergency coolant injection and decay heat removal following a small LOCA, and the LPSI performs a similar function in the event of a large LOCA. In the FCS design, the recirculation mode of LPSI would be used for long-term cooling for all LOCA sizes. In addition, HPSI is used for RCS injection in the once-through cooling mode. The HPSI system is a contributor to five of the seven important FCS accident sequences, while the LPSI is somewhat less important. Based on the above observations, the inspectors determined that the licensee's programs provide reasonable assurance that the SIS will be available for accident mitigation.

7. ONCE-THROUGH COOLING

Once-through cooling (OTC) is the decay heat removal mode of last resort to mitigate the consequences of a total and unrecoverable loss of all feedwater (TLOFW) event. The primary objective of a OTC process is to remove decay heat in a manner sufficient to prevent core heatup and possible fuel damage. There are several important parameters to be satisfied if once-through cooling is to be successful. These include the time from the start of the event until OTC is initiated, the number and flow capacity of the HPSI and charging pumps, and the number and size of the power operated relief valves (PORVs) used.

A plant-specific OTC analysis was performed by Combustion Engineering for the licensee (Combustion Engineering Report dated December 1988, "Engineering Evaluation of Feed and Bleed for TLOFW Events at the Fort Calhoun Station"). The study concluded that the use of two PORVs results in a lower RCS pressure than using only one PORV. The use of one PORV may not be sufficient to keep the RCS pressure below the pressurizer safety relief valve set point unless all three HPSI pumps are available. Essentially, two PORVs limit the RCS repressurization to a point where the HPSI pumps have an early impact on the OTC process. The use of three HPSI pumps provides adequate makeup water to prevent uncovering the core with either one or two PORVs available.

Another important result of the above study was that OTC should be initiated before steam generator (SG) dryout (approximately 20 minutes). The study demonstrates that starting at 10 percent level in the SGs is satisfactory, but waiting for the PORVs to open at the 2500 psia set point (at approximately 26 minutes) will result in uncovering the core. Lastly, operator training is a key factor in a successful OTC operation. The operators should be aware of the key factors which affect the process, namely, the number of PORVs open, when to initiate the process, and the number of HPSI pumps available.

Since assurance of successful OTC requires the availability of both PORVs, the inspectors reviewed the licensee efforts to assure PORV operability. PORVs PCV-102-1 and 102-2 are solenoid-operated relief valves on the pressurizer. These valves are used for the bleed portion of feed and bleed once through cooling. A review of maintenance records revealed that no maintenance had been done to these valves since 1985. Additionally, the licensee produced no procedure indicating that these valves had been cycled under conditions approximating those under which the valves must operate, e.g., operating temperature and pressure. Although the NRC identified the need to test these valves as part of the inservice testing program and the licensee agreed in Revision 3 of the inservice testing program to test these valves, this program revision will not be fully implemented until the end of 1990. In addition, the licensee apparently had never stroked these valves under conditions approximating those under which these valves are required to operate. This condition reduces the confidence that these valves will perform if required to do so. The licensee has committed to perform the stroke test during the upcoming refueling outage in 1990.

Inspector Followup Item (285/8940-06): Review results of the PORV stroke test performed during the 1990 refueling outage.

7.1 Conclusions

The generic PRA-based team inspection methodology focused on seven accident sequences that are considered risk important for the FCS. The OTC process is an integral part of several sequences, and the human and hardware dependencies were extensively examined during this inspection.

As discussed previously in Section 2, the inspectors looked at potential human errors (i.e., training and procedural) that might contribute to the failure of OTC. Based on a review of the EOPs, supporting documentation for OTC and as confirmed during a control room simulation, the operators do not seem to have:

- Consistent success criteria for OTC; and

- An appreciation of the short-time period that is available for the successful implementation of OTC.

To further compound the situation, the licensee has not implemented an effective inservice test for the PORVs to provide reasonable assurance of valve operability.

The generic probabilistic inspection methodology assigned a medium importance value to the OTC mode. This generic methodology was, however, based on a level of operator performance that made OTC human error a small contributor to core damage and included a periodic PORV testing program that provided some assurance of valve operability. The potential failure to implement successfully the OTC mode is higher than normal at FCS and can be attributed both to procedural and training inadequacies and to the current lack of an adequate PORV inservice testing program.

8. SECONDARY COOLANT WATER CHEMISTRY CONTROL

The inspectors reviewed the secondary coolant water chemistry program at FCS. The licensee uses an all-volatile treatment for controlling the pH and chemical impurities in the secondary coolant water, using ammonia, hydrazine, and morpholine as the chemical additives. In addition, the licensee uses a boric acid soak to minimize caustic attack and denting in the steam generators. Since 1984, copper components in the secondary side have been replaced by stainless steel components.

8.1 Conclusions

The licensee's secondary coolant water chemistry control and the boric acid soak appear to be effective in minimizing erosion/corrosion and stress-induced cracking which could lead to tube rupture in the steam generators. The inspectors were informed by the licensee that, in the last in-service surveillance, no tubes in the steam generators needed to be plugged.

9. EXIT MEETING

An exit meeting was held on November 9, 1989, with the personnel indicated in Attachment 1 to this report. At this meeting, the scope of the inspection and the findings were summarized as detailed in this report. The licensee did not identify as proprietary any of the information provided to or reviewed by the inspectors.

ATTACHMENT 1

PERSONS CONTACTED

Omaha Public Power District

*C. Bloyd, Special Services Engineering
D. Bonsal, Licensed Control Room Operator
*F. Buck, Raw Water Systems Engineer
M. Bufford, Licensed Control Room Operator
*J. Chase, Manager, Licensing
J. Connolley, Acting Lead System Engineer
*M. Core, Supervisor, Maintenance
J. Fluehr, Supervisor, Operations and Technical Writing
*J. Foley, System Engineer
J. Friedrichsen, Licensed Control Room Operator
*S. Gambhir, Division Manager, Production Engineering
*J. Gasper, Manager, Training
*W. Gates, Executive Assistant to the President
G. Guliani, Supervisor, Operations Training
A. Hackerott, PRA-Specialist
K. Henry, Lead Systems Engineer
J. Hermann, Supervisor, Initial License Training
K. Holthaus, Manager, Nuclear Engineering
*R. Jaworski, Station Engineering Manager
J. Kelly, Supervisor, System Engineer
L. Kusek, Manager, Nuclear Safety Review Group
L. Labs, Shift Supervisor
M. Lazar, Supervisor, Operations and Technical Training
R. Lippy, Inservice Testing Coordinator
T. Matthews, Station Licensing Engineer
D. Matthews, Supervisor, Station Licensing
T. McIvor, Manager, Nuclear Projects
*K. Morris, Division Manager, Nuclear Operations
R. Mueller, Supervisor, Nuclear Projects
B. Odden, Acting Lead System Engineer, Secondary System
*W. Orr, Manager, Quality Assurance and Quality Control
C. Ovici, PRA-Specialist
*G. Peterson, Plant Manager, Fort Calhoun Station (FCS)
*R. Phelps, Manager, Design Engineer
*A. Richard, Assistant Manager, FCS
M. Sandhoefner, Licensed Control Room Operator
C. Schaffer, Systems Engineer, Safety Injection
*C. Simmons, Station Licensing Engineer
*F. Smith, Supervisor, Chemistry
W. Stecker, Systems Engineer
M. Stewart, Lead Nuclear PRA Specialist
*D. Stice, Nuclear Licensing Engineer
J. Tesarek, Supervisor, Licensed Operator Training
*D. Trausch, Supervisor, Operations

*G. Wood, System Engineer
C. Zaccone, Systems Engineer-Instrument Air

NRC

*R. Barrett, Chief, Risk Application's Branch, Division of Radiation Protection and Emergency Preparedness, Office of Nuclear Reactor Regulation (NRR)
*A. Bournia, Project Manager for Fort Calhoun Station
*J. Jaudon, Deputy Director, Division of Reactor Safety
*T. Stetka, Chief, Plant Systems Section, Division of Reactor Safety
*T. Westerman, Chief, Reactor Projects Section A, Division of Reactor Projects

The inspectors also contacted other members of the licensee's staff during the inspection period to discuss identified issues.

*Denotes those personnel in attendance at the exit meeting held on November 9, 1989.

ATTACHMENT 2

DOCUMENTS REVIEWED

LETTERS

NRC Letter dated May 9, 1988, Milano (NRC) to Andrews (OPPD): "Resolution of Generic Issue No. 124, Auxiliary Feedwater System Reliability, for Fort Calhoun"

Combustion Engineering (CE) Letter dated December 22, 1988, Caruso (CE) to Peterson (OPPD): OPPD-88-170, "Safety Injection and Containment Spray System - Recirculation Flows"

OPPD Letter dated December 27, 1988, Gambhir (OPPD) to Fisicaro (OPPD): PED-FC-88-1355, "NSNRC IE Bulletin 88-04, Potential Loss of Safety Related Pumps"

OPPD Letter dated April 21, 1989, Jones (OPPD) to Martin (NRC): LIC-89-396, "161kV Power Supply Reliability Review"

OPPD Letter dated December 23, 1986: LIC-86-669, "Fort Calhoun Station Unit No. 1 Auxiliary Feedwater System Reliability Analysis"

OPPD Letter dated May 18, 1987: LIC-87-313, "Additional Information on Auxiliary Feedwater System Reliability Analysis (TAC No. 64236)"

OPPD Letter dated June 8, 1987: LIC-87-390, "Information Provided to Support the Auxiliary Feedwater System Reliability Review"

OPPD Letter: LIC-88-524, that submitted Revision 4 of the Inservice Testing Program

OPPD Letter: LIC-89-202, that submitted Revision 3 of the Inservice Testing Program

OPPD Letter dated September 6, 1979: Requested Technical Specification Amendment

NRC REPORTS

NRC Maintenance Team Inspection Report 50-285/89-01

NRC Inspection Report 50-285/87-25, Section 16, regarding Event V configurations

NRC Special Inspection Report 50-285/89-27

OPERATING INSTRUCTIONS (OI)

OI-FW-4, "Auxiliary Feedwater Pump Operation and Testing Auxiliary Feed Operation", Revision 42

OI-CA-1, "Compressed Air System-Normal Operation," Revision 30.

SURVEILLANCE TEST (ST) PROCEDURES

ST-FW-1, Revision 47, "Auxiliary Feedwater"

ST-AFW-3003, Revision 0, "AFW Pump FW-10 Steam Supply Line Check"

ST-SI/CS-1, Revision 54, "SI/CS Pumps and Valves"

ST-ISI-CC-3, Revision 29, "Component Cooling Water Pump Inservice Testing"

ST-PORV-1, Revision 13, "Low Temperature - Low Pressure Power Operated Relief Valve System"

ST-ISI-SI-1, Revision 51, "Safety Injection Valves In-Service Testing,"

ST-DC-3, Revision 14, "D.C. Transfer Switches"

ST-DC-2, Revision 20, "Battery Chargers"

ST-FW-1, Revision 46, "Auxiliary Feedwater"

SPECIAL PROCEDURES (SP)

SP-FW-11, "Auxiliary Feedwater Pump Operational Test"

SP-SI/CS-3, "Special Procedure-Simultaneous Operation of LPCI/HPSI pumps in Min. Recir. Mode"

SP-MOV-1, "Limitorque Motor Operated Valve Inspection," Revision 4

ANNUNCIATOR PROCEDURES

A-21 for Window B-6L, "Instrument Air Pressure Low," Revision 18

A-21 for Window B-6U, "Plant Air Pressure Low," Revision 18

PREVENTIVE MAINTENANCE (PM) PROCEDURES

PM-REG-1, "Periodic Inspection and Filter Replacement for Air Filter Regulators that Supply CQE Components," Revision 0

PM-TXBD, "Replacement of Dessicent in Air Dryers"

PM-UXHV, "Air Dryer Inspection"

MODIFICATION REQUESTS (MR)

MR-FC-88-035, "Hot Leg Injection During Long Term Cooling"

MR-FC-87-021, "Pressurizer Spray Piping Fatigue"

MR-FC-88-120, "Replacement of Motor Operators for HCV-311, 312, 314, 315, 317, 318, 320, and 321"

MR-FC-88-110, "SI-3A/3B/3C Start Signal Logic Change"

TRAINING DOCUMENTS

Nuclear Operations Division Licensed Operator Training Program, Safety Injection and Containment Spray System, Lesson Plan 7-11-22, Revision 4, Incl. Instructor Handbook, Transparency Index and Student Handbook

OPPD Systems Training Manual for Auxiliary Feedwater, ATIAF689

OPPD Systems Training Manual for Emergency Core Cooling, ATIEC689

Nuclear Operations Division Licensed Operator Training Program, Auxiliary Feedwater System, Lesson Plan 7-11-1, Revision 2, Incl. Instructor Handbook, Transparency Index and Student Handbook

MISCELLANEOUS DOCUMENTS

General Engineering Instruction GEI-27, Revision 0, "10 CFR 50.59 Safety Evaluation, " issued November 1989

Inservice Testing Program for Pumps and Valves, Revision 3, dated December 22, 1988

Combustion Engineering Study CE-18074-611, dated July 19, 1979, regarding "Safety Injection Pump Room Temperature Evaluation"

Amendment No. 52 to Facility Operating License DPR-40

Operations Support Analysis Report 87-10, "Determination of the Air-Operated Valves Required for Safe Plant Shutdown," dated April 6, 1988

Combustion Engineering Report, "Engineering Evaluation of Feed and Bleed for TLOFW Events at Fort Calhoun Station," dated December 1988

Chemistry Procedure CMP-3.74, "Dew Point Sampling by Alnor Dewpointer," Revision 0

Updated Safety Analysis Report (USAR) Sections 7, 8, and 9

Design Basis Document SDBD-CA-IA-105, "Instrument Air," Revision 1

Failure Modes and Effects analysis - Static Inverters November 8, 1989

Failure Modes and Effects analysis - Inverters 1 and 2, November 8, 1989

Failure Modes and Effects analysis - 125V Battery Chargers Nos. 1, 2, 3, November 8, 1989

Failure Study of 120V AC Inverters, dated October 30, 1989

Maintenance and Testing History for the following components:

Motor Driven Auxiliary Feedwater (AFW) Pump (FW-6)
Turbine Driven AFW Pump (FW-10)
AFW Pump Discharge Check Valves (FW-173, 174)
Turbine Driven AFW Pump Steam Supply Valves (YCV-1045, 1045A, 1045B)
AFW System Containment Isolation Valves (HCV-1107A, -1107B, -1108A, -1108B)
Containment Sump Recirculatin Line Isolation Valves (HCV-383-3, 383-4)
Power Operated Relief Valves (PCV-102-1, -102-2)
Low Pressure Safety Injection Pumps (SI-1A, -1B)
Component Cooling Water Pumps (AC-3A, -3B, -3C)

Safety Injection/Containment Spray Maintenance Orders (MOs) Reviewed:

871216	863598	858038	858182
852122	852123	863599	872415

Reactor Protection System MOs Reviewed:

843071	842981	844117	850779
867004	851077	852525	857112
860638	867002		

Auxiliary Feedwater MOs Reviewed:

852234	862369	873772	881904
843165	886860	843164	852164
845156	852174	892681	841339

Computerized History and Maintenance Data System (CHAMPS), Maintenance History Summaries for:

Turbine Driven AFW Pump Steam Supply Valve (YCV-1045)
Reactor Protection System (RPS)
Containment Sump Recirculation Line Isolation Valves (HCV-383-3, -383-4)

CHAMPS Incident Report for 345kV and 161kV Power Supply Lines

ATTACHMENT 3

DRAWINGS REVIEWED

OPPD 11405-M-97, Misc. HVAC Flow Diagram, Revision 41
OPPD 11405-M-252, Flow Diagram Steam, Revision 55
OPPD 11405-M-253, Flow Diagram Steam Generator Feedwater and Blowdown, Revision 67
OPPD 11405-M-263, Flow Diagram Compressed Air, Revision 38
OPPD 11405-M-13, Plant Air Flow Diagram, Revision 28
OPPD 11405-M-264, Sheet 1, Instrument Air Diagram, Auxiliary Building and Containment, Revision 35
OPPD 11405-M-264, Sheet 2, Instrument Air Diagram for Turbine Building and Intake Structure, Revision 17
OPPD 11405-M-264, Sheet 3, Instrument Air Diagram, Riser Details, Revision 24
OPPD 11405-M-264, Sheet 4, Instrument Air Diagram, Riser Details, Revision 27
OPPD 11405-M-264, Sheet 5, Instrument Air Diagram, Riser Details, Revision 27

OPPD 11405-E-28 SI System
OPPD MCC 3a (GE 177B 2371), Revision 3
OPPD 136B2492, Sheet 28, Controls YCV 1045, Revision 9
OPPD E-4043, Sheets 1 and 2, Auxiliary Feedwater, Revision 1
OPPD 11405-E-3, 4.16 KV Auxiliary Power One Line Diagram
OPPD 11405-E-6, 480 Volt Primary Plant Motor Control Center One Line Diagram
OPPD 11405-E-8, 125 Volt D.C. Misc. Power Distribution Diagram
OPPD 11405-E-9, 120 Volt Instrument Buses, Revision 29
OPPD 11405-E-10, Primary Plant Power Distribution, Revision 4
OPPD 11405-E-11, 4.16kV Switchgear Schematic, Revision 9
OPPD 11405-E-27, Schematic 4160V Diesel "01" Breaker "1AD1"
OPPD 11405-E-28, Feedwater and Main Steam System SC
OPPD 11405-E-45, Misc. SC&I, Automatic Load Shedding, Revision 3
OPPD 11405-E-60, Reactor Building Tray and Conduit Layout, Revision 11
OPPD,11405-E-137, Controls YCV-1045 and FW/C
OPPD 11405-E-138, Controls YCV-1107 A and B, Revision 6
OPPD 11405-E-139, Controls YCV-1108 A and B, Revision 6
OPPD 11405-E-405, Sheet 2, Wiring Diagram AI-66A, Revision 8
OPPD 11405-E-405, Sheet 2, Wiring Diagram AI-66B, Revision 8

GE Three Line Diagrams 161FS31, Sheets 1-10
GE Switches - AI-30A, AI-30B
GE Wiring Diagrams 161F597, Sheets 6, 7, and 8
GE Wiring Diagram 161F598, Sheet 8
GE Wiring Diagram 161F532, Sheet 9
GE Wiring Diagram 161F593, Sheet 1

P&ID E-23866-210-130, SI/CS P&I Diagram, Revision 51

Instrument & Control Equipment List, 11405-EM-383, Revision 8

Foxboro CD 1A, 2A, 3A, and 4A, Aux. Feedwater Auto Initiation

Drawing C-4175, Sheet 1, "Typical Control Valve Air Source Valve Configurations, Revision 2

Coordination curves for most of the PRA driven components - drawn October 30, 1989 and November 1, 1989 by P. Vovk.

Fuse Curve - min-10 for YCV-1045, dated August 14, 1974

3-Page Coordination Circuit Analysis, dated October 25, 1989

GE and ITE Catalog Type Curves for Molded Case Breakers

Gibbs and Hill Coordination Curves dated May 28, August 27, September 7, and September 23, 1971

Stone & Webster (S&W) SDBD-EE-200, 120 Volts AC Vital Distribution, Revision 0
S&W SDBD-EE-201, AC Electrical Distribution, Revision 0
S&W SDBD-EE-202, DC Electrical Distribution, Revision 0