U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-483/92004(DRP)

Docket No. 50-483 License No. NPF-30

Licensee: Union Electric Company
Post Office Box 149 - Mail Code 400
St. Louis, MO 63166

Facility Name: Callaway Plant, Unit 1

Inspection at: Callaway Site, Steedman, MO

Inspection Conducted: February 1 through March 31, 1992

Inspectors: B. L. Bartlett
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Approved By: Richard L. Hague, Chief, Reactor Projects, Section 3C 4/3/92 Date

Inspection Summary

Inspection from February 1 through March 31, 1992 (Report No. 50-483/92004(DRP))

Areas Inspected: Routine unannounced safety inspections of onsite followup of events, inspection of licensee event reports, plant operations, maintenance and surveillance, and preparation for refueling were performed.

Results: Of the areas inspected, no violations or deviations were identified. One open item was identified and is discussed in paragraph 4. An executive summary follows.

Operations

One unplanned Engineered Safety Features (ESF) actuation occurred during the scheduled shutdown to start the fifth refueling outage. High turbine vibration caused the operators to open the main condenser vacuum breakers in order to slow the main turbine. Loss of the main condenser vacuum would cause loss of the main feedpumps so the Shift Supervisor directed that the last operating feedpump be tripped. Upon trip of the last main feedpump, a Auxiliary Feedwater Actuation Signal was automatically generated. All equipment operated as designed. The licensee will document this occurrence in a Licensee Event Report.

Operational response to Centrifugal Charging Pump (CCP) "B" shaft failure was prompt and precise. Except for the unplanned ESF actuation discussed above, the shutdown to enter the fifth refueling outage was well planned and methodical.

Maintenance/Surveillance

The replacement of the rotating assembly of the "B" CCP within the 72 hours allowed by Technical Specifications (TS) was a notable event that severely taxed the resources of the organization. The replacement went well with only minor problems being identified.

Engineering and Technical Support

Engineering support of the CCP "B" shaft failure and repair effort was timely and effective. By the end of the report period the root cause analysis had progressed to the point that the licensee could state that the cracking was induced by high cyclic loading. The root cause analysis of the initial crack formation was continuing.

Troubleshooting efforts by the licensee during this inspection period identified a wiring error made during implementation of a modification in April of 1991. This error showed a weakness in the review of engineering Request For Resolutions and a weakness in the post-modification test performed following the original wiring change; however, these weaknesses were isolated occurrences.

Safety Assessment and Quality Verification

Management assessment and followup of the "B" CCP and other events which occurred during this inspection period was effective and extensive. The NRC inspector had to remind the licensee of the need to assess the implications of installing the new rotating assembly with the old style locknut, however, this was an isolated occurrence.

The review of two LERs identified that the LERs contained accurate and complete information with thorough root cause analysis and effective corrective actions.

DETAILS

1. Persons Contacted

D. F. Schnell, Senior Vice President, Nuclear
* G. L. Randolph, Vice President, Nuclear Operations
* J. D. Blosser, Manager, Callaway Plant
C. D. Naslund, Manager, Nuclear Engineering
J. V. Laux, Manager, Quality Assurance
J. R. Peevy, Manager, Operations Support
M. E. Taylor, Assistant Manager, Work Control
D. E. Young, Superintendent, Operations
R. R. Roselius, Superintendent, Health Physics
T. P. Sharkey, Supervising Engineer, Site Licensing
G. J. Czeschin, Superintendent, Planning and Scheduling
G. R. Pendegraff, Superintendent, Security
* C. E. Slizewski, Supervisor, Quality Assurance Program
G. A. Hughes, Supervisor, Independent Safety Engineer Group
* J. C. Gearhart, Superintendent, Operations Support, Quality Assurance
C. S. Petzel, Quality Assurance Engineer
* J. A. McGraw, Superintendent, Design Control

*Denotes those present at one or more exit interviews.

In addition, a number of equipment operators, reactor operators, senior reactor operators, and other members of the quality control, operations, maintenance, health physics, and engineering staffs were contacted.

2. Onsite Followup of Events (93702)

On February 3, 1992 at 3:29 a.m. (CST), with the "B" Centrifugal Charging Pump (CCP) in service, the reactor operator (RO) observed a loss of seal injection flow to the reactor coolant pumps. The RO started the "A" CCP and shortly thereafter the "B" CCP tripped. The timed over-current flag was observed to be dropped on the "C" phase of the 4160 V AC breaker for the "B" CCP. Troubleshooting activities by maintenance determined that the shaft of the "B" CCP was sheared. Failure of one of the two high head safety injection pumps caused the licensee to enter a 72 hour limiting condition for operation (LCO). This required that either the pump be restored to an operable status within 72 hours or a plant shutdown be commenced at the end of the LCO.

The non-safety related Positive Displacement Pump (PDP) was out-of-service for some leakage problems. The PDP was made available for emergency service in case it was required and the replacement of the "B" CCP rotating assembly was begun.

During this operating cycle, the licensee had observed signs of degradation on the "B" CCP. This included a slight increase in vibration and a slight decrease in flow output. As a result, the licensee had made plans to replace the rotating assembly during the upcoming refueling outage, Refuel V. The spare rotating assembly had been sent to the pump vendor for balancing and flow testing. Additional spare parts had been procured, training initiated and other preparations implemented for the pump replacement. These preparations aided the licensee considerably in replacing the rotating assembly within the 72 hour LCO.

The licensee estimated that the pump replacement would take 65.5 hours. Actual pump replacement took approximately 68 hours. The NRC inspectors observed portions of the pump replacement and subsequent surveillance testing. Considering the magnitude of the activities and the short preparation time for the change-out of the rotating assembly, the repair effort was accomplished in an efficient manner.

The CCP is an 11 stage centrifugal, barrel-type pump. The pump features an in-line rotor with a pressure balancing drum located just past the last stage. The normal range of pump differential pressure is from 2,457 to 2,695 pounds per square inch (PSID). This differential pressure would cause the pump to "thrust" in one direction. To help reduce this thrust, a balancing drum is installed on the high pressure end of the pump which reduces the pressure along the pump shaft. The pump shaft thus "sees" a lower differential pressure. The balancing drum is held on with a locknut. The location of the break was at the outboard end of the balancing drum locknut.

The reactor vendor had issued Field Change Notice (FCN) SCPM-10539 in 1979 to change the design of the locknut. The old locknut was a one piece design and the new locknut was a two piece design. The licensee had replaced the locknuts of the two CCPs installed in the plant as required by the FCN. The locknut of the spare rotating assembly in the warehouse was not changed out. This resulted in the new rotating assembly being installed with an unapproved configuration. This was not identified by the licensee until after the new rotating assembly had been completely installed. In addition, the pump vendor did not identify that the old locknut was still installed even though the rotating assembly had been inspected and tested at the vendor's testing facilities in December 1991. After questioning by the NRC inspectors as to the operability status of the repaired CCP with the incorrect locknut installed, the licensee initiated Request For Resolution (RFR) 09910A, dated February 21, 1992. RFR 09910A stated that the "B" CCP was operable with the old style locknut until Refueling Outage V when it would be replaced with a new style locknut. This was based upon:

- The old style locknut added additional stresses to the pump shaft which could slowly cause a crack to form and propagate. The crack could be observed if phase angle checks were performed during vibration monitoring. The licensee modified the testing program to evaluate phase angles for signs of crack propagation.

- Vendor calculations and failure analysis of other industry shaft failures supported a minimum operating life of 5,000 hours with the old style locknut installed. Even if the "B" CCP was run continuously only 45 days remained until Refuel V which meant the pump would reach at most 1,100 hours.

- Unless required for a plant event, the licensee would not operate the "B" CCP. Due to a commercial concern, the licensee wanted to run the "B" CCP for less than 500 hours. The FCN stated that if a locknut was changed out with less than 500 hours of operating time on the pump shaft, that only the locknut would have to be changed out. If the locknut was changed out with more than 500 hours, then the pump shaft would have to be replaced along with the new locknut. This would add considerably to the cost of repair.

During normal operations, the licensee endeavors to operate the non-safety related PDP for charging purposes. This helps save wear and tear on the safety-related CCPs. However, the PDP is a high maintenance item and it is not unusual for it to be out-of-service. During these times one of the CCPs would be operated. Due to the commercial concern cited above, the licensee preferred to operate only the "A" CCP for normal charging, since it had the new locknut installed. NRC inspector interviews with reactor operators following the pump repair revealed that not all of them were aware of this constraint. After the NRC inspectors informed licensee management of this, an operations night order was issued explaining the objective of not operating the "B" CCP except when needed.

The licensee removed the portion of the old "B" CCP pump shaft that contained the break and sent it to a vendor for a failure analysis. The preliminary results of the failure analysis showed that the failure was due to high cyclic fatigue. This failure mechanism would be identical to that caused by the old style locknuts, even though the new style locknut was installed. The licensee forwarded information on the operational history of the "B" CCP to the vendor to aid in evaluating the root causes of this failure. The NRC inspectors will continue to follow the licensee's investigative efforts in this matter.

No violations or deviations were identified.

3. <u>Inspection of Licensee Event Reports (LER) (92700)</u>

Through direct observations, discussions with licensee personnel, and a review of records, the following licensee event reports were reviewed to determine that reportability requirements were fulfilled, that immediate corrective action was accomplished, and that corrective action to prevent recurrence was accomplished in accordance with Technical Specifications (TSs). The LERs listed below are considered closed.

a. (Closed) LER 91007: Failure to Verify Load Rejection Surveillance Value of 1352 KW for Emergency Diesel Generators

Background

On November 14, 1991, the licensee was informed by a similar plant that a potential concern existed with the ability to meet the 1352 KW load rejection requirements for the emergency diesel generators. TS 4.8.1.1.2.f(2) states "verify the diesel generator's capability to reject a load greater than or equal to 1352 KW (ESW pump motor) while maintaining a voltage of 4000 plus or minus 320 volts and a frequency of 60 plus or minus 5.4 Hz." This TS requirement had not been met since the initial startup of the plant. Subsequently, both diesel generators were declared inoperable resulting in an entry into TS 3.0.3. The licensee requested a Temporary Waiver of Compliance (TWOC) to allow sufficient time for an emergency TS to be approved by NRR.

Root Cause

The root cause of this event was the licensee's failure to recognize that the ESW pump motor did not draw 1352 KW in its emergency lineup when the TSs were developed.

Corrective Action

The licensee submitted a TS change request to the NRC to indicate the ESW pump motor load as the largest single emergency load rejected by the emergency diesel generators and to delete the 1352 KW load reject requirement. The NRC subsequently granted the TS change request.

Inspectors Review

The inspector reviewed the licensee's safety and hazards evaluations to confirm adherence with NRC regulations. A review of previous LERs was also performed.

The safety evaluation was sufficient to verify that the deletion of the 1352 kw load value from TSs did not represent a substantial safety hazard.

The licensee responded to the event in a timely manner. This LER is closed.

b. (Closed) LER 92001: "A" Train Emergency Exhaust System Incomplete Surveillance Due To A Human Performance Error

Background

During a routine Quality Assurance (QA) audit, on January 21, 1992, it was identified that flow had not been maintained through the "A" Train Emergency Exhaust System for the 10 hours required by Technical Specifications (TS). On September 12, 1991, licensed operators had performed a TS required surveillance for only 9 hours and 21 minutes instead of the required 10 hours.

Licensee's Evaluation of Root Cause and Corrective Action

Root Cause

The root cause of this event was cognitive human performance error during the completion and review of the surveillance procedure acceptance criteria data sheet. A contributing root cause was that the data sheet did not include the 10 hour acceptance criteria nor did it require that the total run time be calculated and recorded.

Corrective Action

The individuals involved were instructed on the importance of closely reviewing all assigned work after completion.

The surveillance procedure was changed to add the 10 hour acceptance criteria and time calculations to the data sheet.

Other similar surveillance procedures requiring specific run times were reviewed. One of the reviewed procedures required a similar revision to add the calculated total run time to the data sheet.

Inspector's Review

The licensee's QA audit reviewed a total of 81 surveillances and only identified this one concern. The operator made this mistake due to a simple subtraction error. The licensee's corrective action of adding the calculation to the data sheet will help to ensure that this error will either not be made again or that if made, it will be identified during the review cycle. This LER is closed.

No violations or deviations were identified.

4. Plant Operations (71707)

The objectives of this inspection were to ensure that the facility was being operated safely and in conformance with license and regulatory requirements and that the licensee's management control systems were effectively discharging the licensee's responsibilities for continued safe operation. The methods used to perform this inspection included direct observation of activities and equipment, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety system status and limiting conditions for operation, corrective actions, and review of facility records.

Areas reviewed during this inspection included, but were not limited to, control room activities, routine surveillances, engineered safety feature operability, radiation protection controls, fire protection, security, plant cleanliness, instrumentation and alarms, deficiency reports, and corrective actions.

Operational Safety Verification

a. Technical Specification 4.5.2.h requires that flow rates through the injection lines of the centrifugal charging pumps be reverified "...following completion of modifications to the ECCS subsystems that alter the subsystem flow characteristics...". During the replacement of the rotating assembly the licensee questioned whether the replacement of the assembly would constitute a modification of the flow characteristic. If it did constitute a modification to the flow characteristics then a flow test would have to be performed. This test would require a unit outage with the reactor vessel head off. The licensee had data from the pump vendor which showed that the pump curve of the replacement assembly was within the existing "A" CCP and the old "B" CCP pump curves. Therefore, replacement of the pump rotating assembly would not constitute a modification to the flow characteristics. Following completion of the replacement, the licensee performed a surveillance test and showed that the new pump rotating assembly fell between the characteristics of the existing "A" CCP and the old "B" CCP. Thus, replacement of the rotating assembly in this case, did not constitute a modification to the flow characteristics of the Emergency Core Cooling System (ECCS) subsystem.

b. The licensee was able to complete the replacement of the "B" CCP rotating assembly within the 72 hour LCO. However, during the replacement, the licensee became concerned that the replacement would take a few hours longer than the 72 hour LCO. Shutting the unit down because the repair effort would take just a few hours more than allowed by TS would not be a safety benefit to the general public and would add an unnecessary cool down/heat up cycle to the unit. Accordingly, the licensee requested from the NRC, a Temporary Waiver Of Compliance (TWOC) which would allow the unit to be maintained at power for longer than the 72 hour LCO would allow. Because the repairs were completed prior to the expiration of the LCO, the TWOC was not required.

c. On March 22, 1992, during the performance of ISP-SA-2413A, "Diesel Generator and Sequencer Testing, Train A," the diesel generator failed to come up to rated voltage and frequency within the required 12 second limit.

   Initial troubleshooting activities conducted on March 22, 1992, did not reveal any problems with the self-excitation circuitry. Therefore, the licensee concluded that the cards in the excitation circuitry were defective. However, subsequent testing performed on March 23, 1992, identified that contacts on a direct current (DC) Agastat timer relay had not closed properly. The contacts are normally open and are required to close immediately on start of the diesel generator (DG), but should then reopen one to two seconds later after the DG has become self-excited. The as-found position of the contacts appeared to be closed; however, approximately 470 ohms of resistance was found between the contacts when the resistance reading should have been zero ohms. A visual inspection of the contacts, after removal, did not reveal any pitting of the contacts which would have accounted for the resistance. Since the cause of the resistance is still unknown, the licensee is considering sending the contacts to the vendor for testing.

After identification of the problem, the licensee solicited a similar plant for a spare relay after determining there were no spare DC Agastat relays in-house. While waiting on the relay to arrive, a decision was made to swap out the contact block on an alternating current timer relay and place it on the DC Agastat timer relay for testing.

When the temporary contact block was installed on the DC relay, the diesel generator was operated for five minutes after reaching the proper voltage and frequency, to ensure that the contacts were indeed the only cause of the diesel generator failure.

Several hours later, the temporary Agastat timer relay was replaced with a new one. After setting the time delay relay, another maintenance run was performed on the diesel generator, then the appropriate section of ISP-SA-2413A was re-performed and passed satisfactory.

d. NRC inspection report 50-483/91019 documented a problem the licensee was having with Estimated Critical Positions and Axial Flux Differences. On March 17, 1992, the licensee met with NRC personnel in Washington, DC. to discuss this issue. Pending the results of the NRC followup to that meeting, an open item will be issued for tracking purposes. (50-483/92004-01)

No violations or deviations were identified.

5. Maintenance/Surveillance (62703) (61726)

Selected portions of the plant surveillance, test, and maintenance activities on safety-related systems and components were observed or reviewed to ascertain that the activities were performed in accordance with approved procedures, regulatory guides, industry codes and standards, and the Technical Specifications. The following items were considered during these inspections: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibration was performed prior to returning the components or systems to service; parts and materials that were used were properly certified; and appropriate fire prevention, radiological, and housekeeping conditions were maintained.

a. Maintenance

The reviewed maintenance activities included:

Work Request No.	Activity
P409170	Replace mechanical seals of the "B" CCP and/or rotating assembly as directed by engineering.
C507316	Modify three spare containment piping penetrations to support steam generator shot peening work.
W143135	Remove, test, and replace main steam mechanical snubber AB01R006251B.
W143137	Remove, test, and replace main feedwater mechanical snubber AE04R020251A.
P504478	Testing of ESW cooling tower fan logic.
P508701	Troubleshooting of ESW cooling tower fan logic.
P478303	Pre-refuel V oil change for "B" auxiliary feedwater pump.
W145185	Replace diaphragm in air actuator for AB HV-0005.
W146270	Troubleshooting activities on open indication circuitry for AB HV-0005 and retermination of wires using Raychem splices.
A134663K	Replace lower prop spring in NB0212, alternate feeder to NB02 bus.
A494761B	Install stoplogs to Essential Service Water Pump "B" forebay.

P484189	Remove Reactor Vessel Head.
P484191	Remove Reactor Vessel Upper Internals.
P510212	Open Spent Fuel Pool Gate to the transfer canal.
S485257	18 Month Preventive Maintenance of "B" Diesel Generator KKJ01B.

During troubleshooting activities under W146270, electricians determined that a wire connection needed to provide open indication at the auxiliary shutdown panel (ASP) had not been made in the terminal box at valve AB HV -0005. A request for resolution RFR-09922A was written to correct the problem.

On March 2, 1992, AB HV-0005, Loop 2 steam supply to the auxiliary feedwater pump turbine had a new diaphragm installed in its air actuator. Valve AB HV-0005 is a normally closed valve and provides position indication in the control room (CR) and at the ASP through two independent circuits.

During retesting of the valve the control room operator was required to stroke the valve and verify that proper indication was received in the CR for the open and closed position of the valve per OSP-AB-V0001, "Main Steam Valve Operability." Proper indication was received in the CR and the surveillance was signed off as satisfactory. Prior to the retest, when the equipment operator (EO) was clearing workman protection assurance for AB HV-0005 at the ASP, the EO did not observe any light indication for AB HV-0005 and informed the CR. After both indication lights were replaced by the EO, only the closed indication light came on.

Subsequent troubleshooting performed revealed that the red indication light was blown. After the light was replaced, the red indication light still would not illuminate. Therefore, it was decided to perform troubleshooting activities at the physical location of the valve on the open limit switch and circuitry for AB HV-0005. At this time the missing wire, connecting field cable N3 to vendor wire 18, was identified. The electricians also inspected the valve box for AB HV-0006 and identified the same problem. What was supposed be a three wire splice including field cable N3, and vendor wires 18 and 8 was only a two wire splice including N3 and 8. After identification of the wiring error, additional work instructions were added to W146270 to properly reterminate vendor wires 8 and 18 to field cable N3 and W146271 was written to repair AB HV-0006. RFR-09922A was written to correct wiring errors on E-2R8900 sheet 32C for both valves.

The wiring error was traced back to a modification performed a year ago and was also applicable to valve AB HV-0006. The wiring error occurred during the implementation of RFR-07461 on April 3, 1991. One of the eight changes required by the RFR was to install raychem splices in valve terminal boxes, AB HV-0005 and AB HV-0006, on cables 22ABK01AF and 22ABK01BF. This modification eliminated the terminal block inside the terminal boxes and was performed in response to Information Notice IN 88-86, Supplement 1, "Operating with Multiple Grounds in Direct Current Distribution System," to eliminate the potential of shorts in solenoid operated valve circuits that were located in high energy line break and main steam line break environments. The RFR was very complicated and included over 50 valves that were to have raychem splices. The mistake in the RFR was due to personnel error in that incomplete changes were made to E-2R8900 sheet 32C for both valves, AB HV-0005 and AB HV-0006. What should have been item 5C on E-2R8900 sheet 32C identifying a 3-wire raychem splice, which would have connected field cable N3 to vendor wires 8 and 18, was omitted for both valves. The error was not identified during the review of the RFR. However, the error could have been flagged during the post-testing of the valves if the test had required verification at both the ASP and the CR. This problem was not identified earlier due to the inadequacy of post-modification test OSP-AB-V0001. The discovery of this problem was fortuitous in that the closed indication light was blown; had this not been the case, this problem would have gone undetected. This problem was not apparent during normal operations due to the normally closed position of the valve. The proper two-wire splices had been made during the modification to show closed indication at the ASP for both valves; thereby masking the open indication problem since the valves were not normally open. It was also discovered during the event that E-27000 had not been properly revised for several valves as a result of the modification.

The licensee's corrective actions included reterminating the splices, writing a Suggestion Occurrence Solution (SOS) for tracking of corrective actions for the wiring error, and reviewing the other valves that were worked during the modification to identify any similar errors. None were identified. In addition, changes were made to E-27000 to show consistency with the in-plant configuration. The inspectors observed replacement of raychem splices for both valves and no problems were identified.

The "B" CCP rotating assembly change-out was a high priority evolution and was discussed previously in paragraph 2. On February 3, 1992, at approximately 10:00 p.m. CST, the NRC inspector entered the "B" CCP room to observe the replacement activities. The three person maintenance crew was observed to be sitting on the floor. When questioned as to their work activities, they stated that they were waiting on Quality Control (QC). The dose rate in the room was low but the contamination levels were high; therefore personnel entry into the room required having to wear a full set of personnel anti-contamination clothing, full plastic over-garments and a full face respirator. The workers had received a de-brief from the previous work team, dressed out, put on their respirators and only then realized that the next procedure step required a QC sign-off. Over 30 minutes had elapsed prior to QC dressing out and arriving at the pump room. The failure of the workers to understand and prepare for the situation ahead of time resulted in them spending an unnecessary 30 minutes in a very hot and uncomfortable work environment.

b. <u>Surveillance</u>

The reviewed surveillances included:

Procedure No.	Activity
OSP-BG-P005B	Section XI operability run of "B" CCP.
RFR-09882A	Data evaluation of Section XI operability run of "B" CCP.
OSP-KA-V0003	Section XI nitrogen accumulator check valve leak rate test.
ISL-GS-00A2A	Zero and Span check of containment hydrogen analysis indication.
ISF-BN-0L932	Functional test of refueling water storage tank protection. "A" level transmitter.
ISF-BB-0F416	Reactor coolant system loop 1 cold leg protection "A" upstream flow.
ISF-BB-0F426	Reactor coolant system loop 2 cold leg protection "B" upstream flow.
ISF-BB-0F436	Reactor coolant system loop 3 cold leg protection "C" upstream flow.
ISF-BB-0F446	Reactor coolant system loop 4 cold leg protection "D" upstream flow.
ESP-GL-H1004	Component cooling water pump room cooler hydrostatic test.
OTS-KE-00010	Unlatch Control Rod Drive Mechanisms
ETP-ZZ-00035	Refueling Performance

On February 14, 1992, during the performance of OSP-KA-V003, "Section XI Nitrogen Accumulator Check Valve Leak Rate Test," equipment operators (EO) mechanically agitated check valves (CV), KA V-0649 and KA V-0650 to assist the valves in seating when excessive leakage occurred. A total of four CVs were tested including valves KA V-0648 and KA V-0651.

The testing configuration required the venting of nitrogen through valves KA V-0649 and KA V-0650, by depressurizing the common nitrogen header, while determining the leakage through valves KA V-0648 and KA V-0651 and then the method was reversed. When venting through the respective valves, flow is much greater than the normal flow through the valves for nitrogen makeup to the accumulator tank (ATs). This causes the line temperature to greatly reduce. Valves KA V-0648 and KA V-0651 properly seated and tested satisfactory when venting through KA V-0649 and KA V-0650. However, during leakage testing of valves KA V-0649 and KA V-0650, when valves KA V-0648 and KA V-0651 were used to vent nitrogen pressure, excessive leakage occurred. The EOs immediately stopped the vent.

The EOs initially agitated valves KA V-0649 and KA V-0650 with a small wrench to aid the valves in seating. The respective ATs were recharged to a normal operating pressure of 650 psig and a vent path re-established for testing. Again excessive leakage occurred, and venting was stopped. The EO contacted the CR and was instructed to agitate the valves with a rubber mallet, while having normal flow through the valves during venting in an attempt to unstick the valves. The valves were believed to have become stuck fully open due to the excessive flow through them during the initial vent, causing temperatures to drop, resulting in check valves that were frozen open.

During valve agitation, the inspectors questioned the validity of the practice with the EOs. After agitation of the valves, the ATs were again recharged to normal pressure, and the required test venting paths were established. The CVs properly seated and retested satisfactorily.

The EOs signed off the surveillance, as partially satisfactory due to mechanically agitating the valves. However, the shift supervisor did not sign off the surveillance as complete due to concerns with the CV test and a possible need for a retest. As a result of management discussions involving operations and engineering, it was decided to retest valves KA V-0649 and KA V-0650. Both valves were satisfactorily retested later the same day without agitating the valves.

Subsequently, engineering requested that valves KA V-0649 and KA V-0650 be retested on February 19, 1992, to assure that agitating the valves did not aid in effecting a satisfactory surveillance. During the retest, valve KA V-0650 passed, but valve KA V-0649 failed. In response to the failure of KA V-0649, the AT isolation valve, KA V-0636 was closed to isolate the check valve and maintain system operability. Good engineering judgement was used in deciding to retest the valves.
Due to historical problems, identified during a review of past surveillances, WR 145310 was written to replace valve KA V-0649 on February 27, 1992. The review identified a total of four leakage problem cases; three instances were on valve KA V-0649 and one instance was on valve KA V-0651. All three surveillance failures on valve KA V-0649 were attributed to different causes. None of the valves were

previously agitated as evidenced by a review of the failed data sheets. The February 14 and 19 failure events appeared to be the only instances in which these valves were agitated. Each case had been properly documented. The agitating of these valves, as a form of minor corrective actions, does not appear to be a common practice. However, as evidenced by the surveillance results of valve KA V-0649 after it was agitated, the impact of this practice on surveillance results can not be accurately determined.

No violations or deviations were identified.

6. Preparation For Refueling (60705)

During this report period the NRC inspectors ascertained the adequacy of licensee procedures for the conduct of refueling operations, ascertained the adequacy of the licensee's administrative requirements for the control of refueling operations and plant conditions during refueling, and ascertained the adequacy of the licensee's implementation of refueling controls.

The NRC inspectors reviewed licensee procedures governing refueling performance, reactor coolant system draining, operational mode change requirements, integrated check out of refueling equipment, draining and filling of the refuel pool, pre-core alteration verifications, and refueling preparation, performance and recovery. In addition, the NRC inspectors reviewed the licensee's outage planning schedule, switchyard work activity schedule, mid-loop level work activity schedule, and reactor head lifting schedule. The items reviewed were compared to information contained in NRC Generic Letters, Information Notices, Temporary Instructions, and NUREG-1449, "Shutdown and Low-Power Operation at Commercial Nuclear Power Plants in the United States", (Draft). The conclusion of the NRC inspectors was, that the licensee had taken all appropriate precautions in the formation of the outage schedule to take advantage of lessons learned in previous outages and of industry lessons learned.

Callaway Nuclear Plant is one of two standard plants. The other standard plant is the Wolf Creek Generating Station (WCGS). The NRC inspectors compared the operating history of the two units to determine if any operational events had occurred at WCGS which could be applicable to Callaway. On September 23, 1991, WCGS experienced a loss of spent fuel pool level and cooling. The NRC inspectors reviewed NRC inspection report 50-482/91-028, which documented the results of the NRC Augmented Inspection Team (AIT) conducted following the WCGS event. The inspectors noted the Callaway Independent Safety Engineering Group (ISEG) had reviewed the WCGS event for applicability immediately following the WCGS event. Discussed below are the items of potential applicability and the results of the followup.

- The initiating event was an electrician closing a breaker door, causing a relay to pick up, tripping breaker PA0101. This resulted in the loss of non-safety bus PA01 (13.8 KV). Callaway has not experienced any similar problems with sensitive relays picking up with door vibrations; however, the licensee has placed padlocks on the doors to provide greater control over entry into the breaker cubicles. In addition, an operations night order was issued explaining the hazards of jarring the door to the operators.

- The loss of PA01 resulted in the loss of non-safety instrument air to the spent fuel pool (SFP) gate boot seal. This gate separates the SFP from the fuel transfer canal. After the air supply was lost, the gate boot seals depressurized allowing water to flow past the seals and into the dry fuel transfer canal. The arrangement of the seals at Callaway is different. First, the design of the boot seals is such that they will continue to function even if they become depressurized. Second, the licensee routinely leaves the boot seals disconnected from the air header. At least once per shift, an equipment operator checks the pressure of the isolated seals and adds air as necessary. In addition, a nitrogen bottle is kept nearby and can be manually lined up to keep the seals pressurized in the event of a loss of air.

- Callaway identified that like WCGS, they also lacked procedural guidance to re-energize a dead bus in the event that electrical power was lost to either 13.8 KV service buss while backfeeding through the main step-up transformers. Operations procedure OTS-MA-00001, "Main Step-up Transformer Backfeed" was revised to add the necessary guidance.

- Procedural guidance was recommended at WCGS to ensure that the fuel transfer tube blank flange and gate valve were closed or that the cavity seal ring be in place with refuel pool drains closed in order to prevent the excessive drain down of the SFP during another gate seal failure. Since the time of this event Callaway has changed out the cavity seal ring with one of a new design. The new design is in place continuously, and would greatly minimize the loss of water even when not pressurized. In addition, the licensee does not routinely operate with the transfer tube open and transfer canal empty. Generally this only occurs at the start of refuel outages when the dry check out of the fuel transfer system is performed.

7. Exit Meeting (71707)

The inspectors met with licensee representatives (denoted under Persons Contacted) at intervals during the inspection period. The inspectors summarized the scope and findings of the inspection. The licensee representatives acknowledged the findings as reported herein. The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents/processes as proprietary.