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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-331/91017(DRP)

Docket No. 50-331 License No. DPR-49

Licensee: Iowa Electric Light
and Power Company
IE Towers
P. O. Box 351
Cedar Rapids, IA 52406

Facility Name: Duane Arnold Energy Center

Inspection at: Palo, IA

Inspection Conducted: October 15 through 25, 1991

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Inspection Summary

Inspection on October 15 through 25, 1991 (Report No. 50-331/91017(DRP))
Areas Inspected: Special modified operational safety team inspection of engineering/technical support, maintenance, safety assessment/quality verification, and operations.
Results: One violation (paragraph 2.3), one open item (paragraph 2.1.3), and three unresolved items (paragraphs 2.1.1 and 4.1.2) were identified. See the Executive Summary for additional results.

1.0 INSPECTION SCOPE AND OBJECTIVES

From October 15 through 25, 1991, a team of five NRC inspectors performed a modified Operational Safety Team Inspection (OSTI) at the Duane Arnold Energy Center (DAEC). The purpose of the inspection was to evaluate the licensee's progress in addressing problems and issues discussed in the last Systematic Assessment of Licensee Performance (SALP) report (SALP 9 - January 1, 1990, through March 31, 1991) and other concerns that arose subsequently. In addition, the inspection included a review of the licensee's improvement programs that were discussed in their response to the SALP 9 report. The team focussed primarily on the licensee's programs and initiatives directed at addressing the concerns in the Engineering/Technical Support and Maintenance areas. The team also focused, though to a lesser degree, on programs and initiatives directed at addressing the concerns in the Safety Assessment/Quality Verification and Operations areas.

2.0 ENGINEERING AND TECHNICAL SUPPORT

In a March 1991 letter and in their SALP 9 response to NRC Region III the licensee committed to overall improvements in their design engineering organization including: increasing staffing levels, decreasing reliance on long term contractors, increasing trending of equipment performance, and resolving technical issues and implementing corrective actions in a timely manner. The team reviewed the following areas to assess the current performance.

2.1 Support of Engineering to Operations and Maintenance

2.1.I System Engineering:

The licensee committed in its March 1991 letter to upgrade system engineering performance by providing more people and by increasing their involvement in: performance monitoring, operations data review, review of common mode failures, and review of periodic maintenance and testing information. Further, the licensee committed to lower the backlog of open engineering work requests.

The team concluded that the system engineering group was staffed with technically competent individuals. The staffing levels appeared appropriate. While a considerable number of the system engineers were new to the company, they either had some commercial boiling water reactor (BWR) system engineering experience or had naval nuclear experience. Through discussions with several new system engineers the team identified a weakness in that there was no formal training program in place. Management expectations for what a system engineer had to do to be fully qualified on a system was not clear. However, it should be noted that the newer engineers interviewed expressed a clear desire to become knowledgeable on their assigned systems. It was observed that the new engineers used the more senior engineers as contacts if questions or problems developed.

The duties assigned to the system engineers appeared appropriate. These included: supporting the operations and maintenance departments, developing quality levels for components for which this had not yet been done, reviewing applicable industry event information to determine if any changes were necessary on their systems, control of engineer work requests associated with their systems, monitoring equipment performance, and supporting day-to-day design engineering activities. The system engineers were also observed to be aware of on-going maintenance activities on their systems and were involved in the planning of technical specification (TS) Limiting Condition for Operation (LCO) maintenance activities.

The system engineering trending program was observed to be under development. Each system engineer was charged with developing a system trending book for their systems. The team discussed this program with several system engineers and found that although they might not have completed development of their trending book they had a good understanding of what component and system parameters which, if trended, could lead to identification of adverse performance. One weakness noted was that management's expectations of what data should be trended and how it should be used was not provided. Also, the information pathways necessary for gathering the needed data were not clearly identified and established.

It appeared that the system engineers were actively supporting the operation of the facility. This was evident by their review of planned corrective and preventive maintenance during system LCO maintenance windows. The system engineers were generally aware of emergent issues on their systems either through the morning meetings or by the issuance of deficiency reports (DRs) or corrective maintenance requests (CMARs). However, it was not clear if the system engineers were receiving feedback on the actual maintenance performed and made aware of any abnormalities. The system engineers did not receive a completed copy of CMARs to ensure that they were aware of potential issues. Further, the more experienced system engineers received calls from operations and maintenance personnel on their systems. As the newer engineers become familiar with their systems their contact with plant personnel should increase as they are viewed as more of a resource.

The team evaluated several issues in which system engineering was involved and found generally good understanding of system design and use of engineering principles and calculations to backup or develop conclusions.

- On the high pressure coolant injection (HPCI) system the team reviewed: the performance upgrade program, system engineering responses to various industry generic communications, and system quick start testing. Generally the system engineer was knowledgeable about this system. However, in one case a weakness was observed with the review of industry generic information.

The performance upgrade program was found to be a good initiative to increase system performance. This program included modifications to the turbine control system which have been effective at other BWRs in reducing system unavailability due to failed quick start system testing failures. Also included was the installation of a nonsafety-related lube oil keep fill pump. This pump allowed the system to remain full and pressurized, thus minimizing the lube oil pressurization perturbation following the start of the auxiliary lube oil pump. Also added was a monitoring system which recorded key system parameters allowing for system engineering evaluations. The team found that the parameters monitored were good indicators of system performance and were being trended by the system engineer.

The team identified that the design engineering review of General Electric (GE) service information letter (SIL) 475, dated November 7, 1988, was not properly handled. This SIL dealt with the potential for unnecessary HPCI and reactor core isolation cooling (RCIC) high steam line flow isolation because of a nonconservatively low setpoint (i.e., less than the differential pressure represented by 300% steam flow at the high pressure injection point just below the first safety relief valve lift point). The SIL addressed the need to possibly change the setpoint because the steam flow at this higher injection pressure would be higher than that observed during normal system operation. The team's review of an August 22, 1989, evaluation of the SIL found it unacceptable. The licensee's reviewer apparently did not understand the reason for recalculation of the isolation setpoint and thus made a generalization that the current conditions were adequate. Justification for this was that the setpoint was conservatively low, however this misconception was the reason for the SIL. The licensee's reviewer did identify that there had previously been high steam flow isolations on HPCI and that further review of both the instrumentation installation and isolation setpoint calculation were warranted.

The need to conduct this additional review was given a commitment tracking number and was open at the time of the inspection. Following the team's identification of this issue the system engineer stated that the initial review was not proper. The licensee was completing the review of this SIL, which could lead to a technical specifications change if the current setpoint values are too low. Pending NRC review of this determination this issue will be tracked as an unresolved item (50-331/91017-01).

HPCI SILs found to have been properly dispositioned were: SIL 351, Revision 2, dated April 4, 1990, dealing with changes to the control system calibration procedures for the HPCI and RCIC turbine control systems; and SIL 392, Revision 1, dated November 28, 1990, dealing with an improved HPCI turbine mechanical-hydraulic trip design. The team found that the maintenance procedures for HPCI and RCIC had been properly updated to address the issues raised by these SILs.

The team reviewed the HPCI quarterly quick start surveillance test (45D001-Q, dated September 10, 1991) being conducted by the licensee. The team identified that the licensee's methodology was generally sound, however testing which might have identified control system response problems, before they could develop during an injection, was not being conducted. Information about an oscillatory HPCI response during an actual injection was available to the system engineer in an industry communication from another utility in April of 1990. At that utility, the system exhibited an oscillatory response during an actual injection following a reactor scram. The previous quick start surveillance testing, with pump discharge to the condensate storage tank, had not been able to identify the control system problem. They found that performing step changes in system flow and speed in both automatic flow and in manual speed control, during surveillance testing, was sufficient to identify oscillatory responses and allow for control system adjustments. The system engineer was reviewing the need to incorporate this type of testing into the licensee's program.

While reviewing the basis for test acceptance criteria the team also noted an inconsistency between the HPCI Updated Final Safety Analysis Report (UFSAR) design basis and the Appendix K loss of coolant accident (LOCA) analysis. UFSAR Table 6.5-2 stated that the maximum allowed delay time from the initiating signal to rated flow available with the injection valve fully open was 30 seconds. UFSAR Table 6.5-2 also stated that the maximum time from receipt of the initiation signal to the injection valve being fully open was 20 seconds. The team identified that the test did not specifically check that the injection valve would come open within 20 seconds of receipt of the system initiation signal. The test did require conduct of normal inservice stroke time testing of this valve, and would have verified that it would stroke open in 20 seconds. However, during an automatic initiation of the system there is a delay in the injection valve receiving an open signal until the hydraulically operated turbine steam admission valve begins to open. This delay would occur because the auxiliary oil pump would have to pressurize the system to allow the valve to open. Through discussions with the system engineer it was not clear that he knew of this UFSAR design requirement.

While reviewing the significance of not testing the opening time of the injection valve from the initiation signal, the team identified that the licensee's Appendix K analysis stated that the system basis used for that evaluation was 45 seconds from the initiation signal until the system was at rated flow with the injection valve fully open. It was not clear that the system engineer knew of the Appendix K analysis and that it differed from the UFSAR system specifications. It was also identified that the Appendix K analysis system basis was not considered for a UFSAR change because design engineering wanted to use the UFSAR values, keeping the margins between the UFSAR and the Appendix K analysis separate. If difficulties with meeting the design basis were encountered the added margins could be applied on an as-needed basis. The team found this acceptable but confusing, since the system engineers were not fully aware of the system design basis applied in the LOCA analysis for their systems.

- The team reviewed emergency service water (ESW) and residual heat removal (RHR) service water (SW) system issues including system and component performance testing and a proposed modification. The system engineer was new to the company, but had experience at another BWR. He was knowledgeable on current system performance and maintenance issues, but expectedly relied on the previous system engineer to provided historical insight and perspective.

  The team found that the special testing conducted by the licensee to determine the flow rates to ESW system components and the heat removal capacities of ESW and RHR SW heat exchangers were acceptable. Review of Special Test Procedures (STPs) 163A, RHR Heat Exchanger Heat Transfer, and 163D, RCIC Room Unit Cooler Heat Transfer, both dated June 30, 1990, indicted that these procedures were of good quality and that the methodologies used were acceptable. The review of these procedures also showed that the heat exchangers were able to remove their design heat loads when tested separately at their design flow conditions. The system engineer stated that continuing testing of the ESW and RHR SW flow rates and heat transfer capability would be conducted on a cyclic basis through a maintenance procedure that would be run when the heat exchangers were loaded to the maximum extent possible.

  The team reviewed STP 163K, ESW Flow Verification Special Test, dated June 20, 1990. This test was well prepared and indicated a proper system line-up during performance. However, the flow testing conducted in September 1990 indicated that the control building chillers, the RHR pump seal coolers, and the core spray pump motor coolers, for both trains, were receiving less flow than the UFSAR flow rates (specified in Table 9.2-1) used as the acceptance criteria for the test. The team found that this STP had not been signed off as either satisfactory or unsatisfactory at the time of the inspection. System engineering justified this lack of formality because they could not verify the basis for the flow rates in the UFSAR. The team found that the licensee never conducted an evaluation for system operability, but rather waited until an engineering evaluation of the design basis was conducted some months later. This evaluation, conducted by the architect engineering company, recalculated the system design basis heat loads and revised the component flow rates and thus the total system flow rate requirements. The licensee subsequently updated the UFSAR with these new component and total flow requirements. The team verified that the September 1990 as-found flow rates met these revised requirements.

The licensee had also submitted a TS change to delete the ESW pump flow versus river water temperature curve, to be replaced by a total system flow value consistent with the new design calculations. As part of the TS amendment review process the NRC staff asked for, and was provided by the licensee, the calculations to substantiate the revised flow rates. The NRC was in the process of reviewing the technical adequacy of the new ESW system design basis requirements. The failure to perform a system operability determination will be tracked as an unresolved item (50-331/91017-02) pending further NRC review of the new design basis calculations.

While walking down the ESW system the team noted that the ESW pumps supplied the pump motor cooling flow to the RHR SW pumps, thus both pumps needed to be run if the RHR SW pump was in operation. The team found that there was an open engineering work request (EWR), dated June 5, 1987, which requested that the design be changed to allow the RHR SW pump to supply its own cooling flow. The EWR stated that a design review was needed and that the engineering target date was December 1988. This modification received funding for the 1992 year budget and should reduce the run times on the ESW pumps.

- Main steam isolation valve (MSIV) issues, including review of responses to generic industry information, the design change package (DCP) for modifications conducted during the 1991 refueling outage, and a root cause evaluation for valve difficulties identified during a forced shutdown in June 1991, were reviewed by the team. The team found the system engineer to be very knowledgeable on the operation and modification issues concerning these valves.

  The team reviewed DCP 1476, MSIV Upgrade Project, installed during the 1990 refueling outage. This modification included upgrading the actuator (including the springs) and installation of disc pad guide assemblies. The team found that this modification was appropriate to improve the ability of the MSIVs to limit leakage and to address local leak rate test (LLRT) performance problems.

  The team reviewed the actions taken by the licensee on GE SIL 477, dated December 13, 1988, and found the issue adequately resolved. This SIL dealt with the possibility that the MSIVs inside the drywell might not fully close, or might reopen, without nitrogen pressure (i.e., spring only) at the maximum drywell pressure following a LOCA. This could occur because when closing or when closed, the actuator lower piston area is vented to the drywell. As part of the modification discussed above, shop tests were conducted which duplicated the LOCA closure conditions. The licensee identified that the MSIVs would not shut and stay shut under this condition with the spring force only. The team reviewed calculation CAL-IEP-M90-15, Revision 0, dated December 17, 1990, which documented an engineering evaluation of nitrogen pressure required for an MSIV to go shut and stay shut under the LOCA closure conditions. Based on this calculation, the licensee determined that during normal operation if nitrogen pressure bleed off of the supply to an MSIV there would still be sufficient pressure to close the valve if the operators manually closed it prior to it drifting to 90% open as indicated in the control room. Also, at this point closure of the outboard MSIV in the affected line would be necessary to ensure adequate isolation if a LOCA occured. The team verified that the licensee revised the low nitrogen pressure alarm response procedure to address this concern. No deficiencies were noted.

The above SIL also identified that a UFSAR change might have been needed if the MSIVs spring only closure was specified as a design basis. The licensee's quality assurance department identified on corrective action report (CAR) 90-130 that the MSIVs spring only closure was specified as a design basis and that a UFSAR change had not been addressed by a 10 CFR 50.59 safety evaluation before the unit was restarted following the outage. The team noted that a safety evaluation was subsequently done and the UFSAR was changed during the June 1991 update to reflect the new inboard MSIV closure requirements.

- For the standby liquid control (SLC) system the team reviewed how the licensee was addressing a concern on loss of pressure on the pump discharge accumulator. The team found that the system engineer was relatively new to DAEC but had previous BWR experience. The system engineer was knowledgeable about this system and was able to address the team's technical questions very well.

EWR 90-015, dated January 18, 1990, indicated that the pump discharge accumulator, required by the UFSAR, had been found to be charged with less than the required 450 psig of nitrogen. This accumulator had been found discharged previously. This was of concern to the team because there was no evaluation of the necessity of the accumulator charge on the operability of SLC. The system engineer's review of this condition indicated that it would require a modification to install a permanent gage to allow monitoring of the pressure during operator rounds. This resolution appeared sound, however the modification had not been conducted or placed on the active projects list.

The team also reviewed maintenance procedure ACCUMU-G250-001, dated March 4, 1990, used to perform the monitoring of the accumulator pressure. This procedure allowed the monitoring of the accumulator pressure and if the pressure dropped to less than 450 psig, specified the addition of nitrogen. However, the procedure, which was performed semi-annually, did not specify that a deficiency report should be written if nitrogen needed to be added so that further engineering evaluation could be conducted. This was considered a weakness.

2.1.2 Vendor Manuals

The licensee committed to reduce the backlog of unreviewed vendor manuals to zero by the end of 1991. This endeavor was developed to bring the existing manuals up to date and to allow the existing processes to control the manuals as updated information was received. The team discussed the vendor manual program with the discipline and component (DSCO) engineer in charge of the program and reviewed the program procedures. The team determined that the program, if fully implemented, would be generally sound.

Recently the licensee completed their first stage of the vendor manual program, which consisted of ensuring that the site library had up-to-date manuals for both safety-related and nonsafety-related equipment. The review and updating of these manuals were conducted by the configuration control group. The team reviewed several vendor manuals which had been updated by this initial review. The manuals included specific computerized vendor manual review sheets which identified the specific attributes in the manuals and a listing of the components affected by the manuals. The team evaluated several manuals and found that each review sheet had been very well prepared. For specific systems, such as diesel room ventilation and the remote shutdown panels, the specific components used in each case were provided in an individual system book.

Following the initial review, the manuals were turned over to the procedures review group. This group reviewed, or will review, the manuals to ensure that site procedures for operation and maintenance properly reflect the vendor manual requirements. The team reviewed the technical manuals for the emergency diesel generators and the HPCI and RCIC systems for surveillance and maintenance actions and compared them to the applicable operations and maintenance procedures. No deficiencies were noted. While the team did not review the control of preventive maintenance activities recommended by vendor manuals, it was noted that such a review was not clearly specified by procedure.

Following the procedure review, each manual was turned over to the DSCO group charged with ensuring that the manuals were maintained up-to-date as new information was received. The procedures for yearly contact with the vendors, to ensure that no manual changes were made and not received by the licensee and for vendor contact if the licensee identified a problem with the manuals, was well defined and appeared proper.

2.1.3 Engineering Support to Maintenance

The team found that the system and component engineers were generally involved with maintenance on their assigned systems or components. One strength was a planned training program for the component engineers which allowed them to be assigned to maintenance for a half a day to follow field activities. However, better prioritization of engineering resources to remedy known problems would appear to be warranted. Two specific examples where this was evident were:

- Two catastrophic failures of RHR SW pumps and one failure of a river water supply (RWS) pump have occurred at DAEC. The failures of the RHR SW and RWS pumps both took place after the pumps had been operating for over five years. The RWS pump was replaced with a new pump in November 1990. The intent was to send the failed pump to a vendor for overhaul and, upon its return, replace another RWS pump when it reached the point of having been operating for five years (September 1991). However, due to difficulties in obtaining engineering support to write up the purchase order, the failed pump was not shipped off site until September 1991, or ten months after it was first removed. Consequently, the pump that it was scheduled to replace after being rebuilt was still operating, though it had been declared technically inoperable due to excessively low differential pressure. The pump that was shipped off for overhaul was not scheduled to be back on site until December 1991. The licensee decided to refurbish the pump that had been declared technically inoperable. They planned on replacing the old style impeller in a spare pump bowl with the new style impeller and using this assembly to accomplish the refurbishment.

- A pipe support's base plate anchor bolts were found loose on the steam inlet to the HPCI turbine during the 1990 inservice inspection. This discrepancy was documented on corrective maintenance action request (CMAR) A00572, dated April 20, 1990. Upon attempting to torque to the required 400 ± 80 ft-lbs on the 1¼" diameter concrete anchor bolts, it was found that the four bolts could be torqued only to 150, 150, 80, and 60 ft-lbs, respectively.

  Engineering performed an evaluation (CAL-IELP-C90-15, Revision 1, dated August 13, 1990), which concluded that the torque values achieved were adequate. The methodology used to qualify these bolts at the low torque values was found by the team to be unique. The calculation assumed that the bolts were only ¾" in diameter and torqued to 60 ft-lbs.

The ½" bolts were selected because the 60 ft-lbs achievable on the 1¼" bolts was acceptable for the smaller diameter bolt. In an attempt to validate this methodology, the licensee recorded a telephone memo with the bolt manufacturer (Hilti Company). The memo stated that the manufacturer agreed with the approach taken. The team was unable to come to the same conclusion and raised two issues with regard to this evaluation:

a. The telephone memo discussed the acceptability of validating a 150 ft-lb torque for the 1¼" anchors, not a 60 ft-lb torque as used in the analysis. The licensee subsequently contacted the manufacturer and was told that they felt the methodology would also apply to a 60 ft-lb torque.

b. The analysis assumed a vertical load of 2000 lbs on the base plate anchor bolts when, in fact, the actual load was approximately 3000 lbs. This load was a result of the variable spring hanger, installed between the base plate and the pipe, having a setting of approximately 3000 lbs. The licensee subsequently recalculated the interaction equation and found this load acceptable.

The team requested that the licensee provide the basis (e.g., test data) supporting the relationship between anchor bolt torque and load capability in order to support the methodology used to evaluate this hanger assembly. Pending NRC review of the technical basis of this methodology, this issue will remain an open item (50-331/91017-03).

2.1.4 Trending

Many individuals and departments were involved in trending activities. Activities included system performance monitoring, predictive maintenance, component trending, the Emergency Diesel Generator Reliability Program, and the Maintenance Trending Program. The team reviewed procedure Nos. 1408.14, Plant Performance Monitoring and Trending, 1208.2, System and Component Performance Monitoring and Trending, and 108.2, Performance Monitoring Program. The procedures were viewed as being somewhat redundant and unclear in that responsibilities and goals were not clearly defined. Several interviews and meetings were conducted in an effort to understand the licensee's overall program. From these interviews, it was also apparent that some informal activities and communication between personnel had resulted in identifying adverse trends, such as failures of components utilized in separate systems. Such activities were viewed as an important part of the licensee trending effort in that component trending reviews were performed only once a year and only for select components. While this informal communication between individuals was encouraged, it was the team's judgement that the overall trending program should be more clearly defined. The licensee committed to review the appropriate procedures and overall program to better define responsibilities, methods, and goals of trending efforts.

The team specifically reviewed a sample of trending efforts performed by the Maintenance Engineering Department. Activities reviewed included the following:

- Vibration Analysis - Analysis parameters, as well as process parameters such as bearing temperature load, current, and speed, were trended. Monthly or quarterly reports were generated based on data collection frequency. Trending reports identifying adverse trends classified equipment in "Action Required" status, "Alert" status, or "Warning" status, commensurate with the severity of the adverse condition. Vibration analyses were being performed on approximately 110 components.

- MOV Program - Diagnostic testing of all MOVs in the Generic Letter 89-10 program was performed on a scheduled basis as well as after post-maintenance. Parameters such as thrust, motor current, contactor drop out times, and torque switch settings were trended to establish baseline values and identify degradation of MOV operation.

- Check Valves - A decision to purchase nonintrusive test equipment for check valve evaluations was made by the licensee. Expected trending attributes included hinge pin condition, bushing condition, and proper seating.

- Heat Exchangers - Attributes such as eddy current and ultrasonic test results were trended to identify tube wall thinning or shell corrosion and erosion. Temperature monitoring and trending was performed to aid in evaluating heat transfer efficiency.

Overall, the trending efforts by the licensee were viewed as adequate.

2.2 Modification Controls

In order to increase management attention to the review and prioritization of modifications, the licensee established a priority review board (PRB). The team reviewed PRB procedure PRB-01, dated October 16, 1991, and attended a PRB meeting. This group reviewed and approved the outlay of capital funds for modifications. The procedure specified a clear method by which each PRB member could rate a new modification or project based on its impact on plant capacity factor, industrial safety or radiation exposure, nuclear safety, and regulatory performance. Good interaction between managers and individuals speaking on their specific modifications or concerns was observed by the team. Based on the rating and the projected cost of a modification, the PRB would then weigh the cost versus priority and identify a list of modifications which should be completed. This list was then passed on to the Nuclear Division Director. A weakness identified by the team was that modifications that were cut from the 1991 budget did not receive the in-depth prioritization review that a new modification would get. This meant that these modifications might not get factored into the overall priority of the site. Another minor weakness noted was that the design engineering procedures did not fully reflect all the ways of utilizing the PRB.

Through discussions with numerous site personnel the team found that the modification process was well understood. The EWR was the document used by individuals to identify a deficiency which might require a design change. The EWR process is discussed below. System engineers were tasked with prioritizing the EWRs that required design changes on their systems and presenting the top three items along with preliminary cost figures to the project engineering group. The project engineering group prepared conceptual design packages and more detailed cost figures for presentation to the PRB. Once approved by the PRB, a modification would go to the project engineering group for design and construction as discussed below.

The team reviewed the EWR process and the backlog of open EWRs. The process documented in procedure 1203.01, dated August 5, 1991, was clear. However, it did not reflect how the PRB was being used in the prioritization of modifications. There were approximately 500 unresolved EWRs, some dating back to 1983. A review of approximately 30 such EWRs on safety-related components showed that the majority were written to document minor system or component problems, such as a request for the installation of an instrument isolation valve where one was not installed by original design. Others were written to specify engineering studies of long-term issues such as installation of an analog trip system or removal of unnecessary snubbers. The team found that the type of issues being documented on EWRs was proper.

The team found that the system engineers were generally familiar with the open EWRs on their systems, but in some cases felt that they were not getting management support to correct the minor conditions. This lack of support for these older issues seemed to be due to the prioritization process and a design change process that treated even the most minor modification to a safety system as a major design change. This appeared to be a weakness in the process, which left long standing minor modifications open, while more costly modifications were completed.

The project engineering group was established during the recent reorganization to provide better support to the design change process. The licensee's management intended that this group would control the entire design process from conceptual design to installation and turnover to the plant. The project engineering group only started major work on a modification after it had been approved by the PRB. A project team was established for each modification. The project team generally included a leader and design, construction, and systems engineering representation, and if applicable a DSCO engineer. The OSTI team found that the method of clearly identifying each project on a project plan was good. Further, monthly updates were effective at tracking the progress toward project goals such as design reviews and verification, modification package development, construction, and package closure. The team also found that the process used by the project engineering group was effective at controlling the outage work scope and that design documentation packages were being completed at or near the desired dates.

The licensee's policy of updating drawings before the modifications were turned over to the plant appeared to be functioning well. This included a system walkdown by the construction engineer to verify design as-built conditions. The construction engineer then updated the plant drawing by showing the new as-built configuration in a clouded area.

As part of the inspection, the team reviewed modification package PMP-0038, Electro-Hydraulic Control (EHC) Pump Replacement. At the time of this review PMP-0038 had been reviewed and approved for use and was scheduled to be implemented during the upcoming refueling outage. The scope of the modification was to replace the existing EHC pumps with a new model. The new pumps, as well as a conversion kit and a spare pump, were being procured from GE. The basis for the change was that the installed EHC pumps were obsolete and replacement parts were no longer available from the original manufacturer (Vickers). As a result, rebuilding each pump was becoming economically infeasible. In addition, GE in Technical Information Letter (TIL) 731-3, recommended the replacement due to possible thrust bearing failure as a result of overload induced metal fatigue. The review of the modification package identified one problem. Section 5.2 specified construction acceptance testing such as leak testing, measurement of motor current amperage values, and obtaining of baseline vibration and thermography data. However, it failed to provide testing requirements and acceptance criteria for many other aspects of system performance that could be effected by the new pumps and motors (e.g., comparison of the pump against the pump curve, etc.). The package did have information that indicated that the licensee had requested GE to supply appropriate test acceptance criteria. However, there was no mechanism in place to track the necessary changes to the test procedure. Discussions with system and design engineering indicated that this had been missed in the apparent rush to get the package out at least six months prior to the outage. On October 24, 1991, the licensee issued a field variance to PMP-0038 to provide a tracking mechanism for the inclusion of any additional testing and acceptance criteria after receipt from GE.

2.3 Configuration Control and Labeling

The licensee committed in their March 1991 letter to the NRC to upgrade their configuration control over system components on plant drawings. The team discussed this program with the Configuration Control Manager. He stated that there was a four step plan being used to update and verify system drawings. These phases consisted of determining the drawings which the operators need to have in the control room, determining what information the operators and engineers wanted on the drawings, revising the drawings to reflect any new information, and finally performing field walkdowns to verify as-built configurations. The first two of these phases had been completed and the licensee projected completion of the other two phases in approximately three years.

During walkdowns of diesel generator support systems, the team identified that there were two valves on the lube oil make up tanks for each machine which did not reflect the position shown on piping and instrumentation diagram (P&ID) M-132. Also, the P&ID reflected that caps were installed downstream of these drain valves when none existed. Further, the team identified that there were tygon tubes connected downstream of three of the four valves. The team also noted that on each machine a rubber hose ran from the lube oil drain valve to the lube oil makeup tank which was not shown on the P&ID. This is a violation (50-331/91017-04) of 10 CFR Part 50, Appendix B, Criterion VI, Document Control.

As part of this review the team also evaluated the licensee's labeling program. The program was found to be well defined in the plant labeling guidelines, dated March 31, 1987. The team noted that there were numerous manual valves, specifically in the diesel generator systems, which were not tagged in accordance with the guidelines. In these cases, the valves either had no tags or had an orange tag which did not reflect the valve component numbers represented on the system P&ID. The licensee stated that these tags were left over from a previous initiative and that the valves were not in the tagging program. The team found that this was a weakness in the labeling program. The licensee stated that they were reviewing these types of issues.

2.4 Work Control Task Force Activities - Lessons Learned From The 1990 Refueling Outage

During the 1990 refueling outage, there were repeated instances of inadequate control of work activities assigned to GE. Numerous communications took place between GE and the licensee over performance difficulties on the GE controlled work. The primary deficiency was a failure to follow established procedures. A contributing cause was inadequate direct supervision of work activities. For the upcoming outage, the licensee completely revamped the outage organization with regard to control of contractors. A training program was to be developed specifically for contractors that would identify their outage tasks, provide a training standard for each task, review the worker's qualifications against the standard, train to the standard, and test against it. In addition, technical staff supervisor training was to be developed that incorporated work standards and required training to the standards.

To provide more comprehensive management of the contractors, project team leaders and technical leaders were to be responsible for the organization and coordination of work assigned to their project teams. The project team leader was to be the licensee's designated interface for individual major jobs. They would then have the overall responsibility for the successful completion of the work under their cognizance. These project teams were to assimilate the contractor craft personnel and place them under the guidance of core personnel who had past outage experience at the site. In addition, all work was to be done using the licensee's procedures and the licensee was to provide all quality control coverage.

2.5 Procurement Process and Spare Parts

As a result of difficulties in maintaining an adequate supply of spare parts, the licensee formed a task force to recommend changes in their procurement process. One of the results was the formation of the team concept by the relocation of most of the personnel associated with procurement, (i.e., warehouse workers, quality assurance, and procurement engineering) into the same location. In addition, the number of dedicated procurement engineers had been increased from four to seven engineers. Computer tracking of spare parts had been improved such that every item had a warehouse location specified. Inventory control was also done through the computer, with minimum levels specified to key reordering. For the long term, the licensee was planning to develop a bill of material for major pieces of equipment. The bill of material would have all required spare parts on one list. Earlier identification of required parts by more comprehensive work package review had also been incorporated. These improvements and planned improvements to the procurement process appeared appropriate.

2.6 Support To BOP Activities

The scram frequency reduction program referred to by the licensee in their March 1991 letter to the NRC resulted in a review of recent scrams. The unit scrammed in September 1990 and again in June 1991 because of the failure of solder joints in the instrument air and nitrogen systems, respectively. Following the first scram, an inspection of the solder joints that were installed by a specific design change package in the instrument air system was performed. The second scram prompted an inspection of a random sample of 2 and 3 inch solder joints in the instrument air piping. The results of the inspections were analyzed and tests and development work efforts performed to verify the acceptance standard for bond area and the uniformity of the bond. Based on these investigations, the importance of bond uniformity was confirmed and acceptance standards were developed for production solder joints. Ultrasonic inspection techniques and dimensional fit up requirements were also developed and training provided to the crafts and quality control inspectors. A detailed solder standard, an ultrasonic examination procedure, and a solder qualification specification that the licensee said lead the industry in this area resulted from the engineering evaluations of the solder joints.

Through the scram frequency reduction program the licensee developed the need to make modifications to the feedwater control system to enhance its ability to prevent a scram if instrument air was lost. These modifications were not formalized at the time of the inspection but should help to prevent transients. Overall, this program appeared effective at identifying root causes and proposing corrective actions.

3.0 MAINTENANCE

3.1 Post-Maintenance Testing

The licensee's Post-Maintenance Test Program was described in Maintenance Directive No. MD-024. Post-maintenance testing was subdivided into both "maintenance testing" to ensure that the component had been properly repaired and "operational testing" to verify that the component was able to perform its intended function. For "on-line" maintenance activities, the Maintenance Planer (i.e., mechanical, electrical, or instrumentation and control (I&C)) was responsible for ensuring that the appropriate maintenance testing was specified. For maintenance activities planned for plant outages, the Maintenance Group Leader from the Maintenance Engineering Department (i.e., mechanical, electrical, or I&C) was responsible for specifying the appropriate maintenance testing. In both cases the Operation Maintenance Coordinator was responsible for specifying the appropriate operational testing. For Quality Level I, II, III, or American Society of Mechanical Engineers (ASME) related components, quality control (QC) was required to review the specified testing activities to determine any required inspection coverage. Following post-maintenance testing, the operations Shift Supervisor (SS) was responsible for reviewing the test results prior to returning the component to an operable status.

In an effort to achieve consistency among the individuals responsible for the Post-Maintenance Test Program, the licensee conducted training. The team reviewed the training material, including a required exam, and Maintenance Directive MD-024, and found them acceptable. Post-maintenance testing of motor operated valves (MOVs) was controlled by a matrix which specified test requirements for various maintenance activities. The team reviewed this matrix and found it to be an effective method of controlling post-maintenance test activities. This was considered a strength. Within the matrix, select test activities such as static diagnostic testing were waived if they applied to packing adjustments, provided that the torque on the packing gland bolts did not exceed the torque recorded during the last test. The licensee indicated that they had performed a test program to support this practice. However, the program was not well documented. The licensee agreed that a review of this practice would be performed and a formalized evaluation would be documented.

The team also reviewed numerous corrective maintenance action requests (CMARs) and preventive maintenance action requests

(PMARs), both closed and pending, and found the post-maintenance testing to be adequate. Overall, the Post-Maintenance Testing Program was judged to be adequate.

3.2 Predictive Maintenance Program

There were several engineering organizations within the Design Engineering Department that trend data to monitor component and system performance. The programs utilized the analysis techniques of vibration analysis, thermography, oil analysis, and instrument calibration deviations. The data were evaluated by engineering and recommendations for equipment or parts replacement were made. The licensee had experienced both successes and failures in their trending program. Early detection of turbine and condensate pump bearing deficiencies by vibration analysis allowed repair prior to failure of those components. However, two catastrophic failures of residual heat removal (RHR) service water (SW) pumps and one failure of a river water supply (RWS) pump occurred even though monitoring was being performed per the ASME Code. ASME Code testing was not adequate because of the pump design configuration (i.e., deep draft pumps). In addition, even though the licensee had indicated that they place a high degree of emphasis on predictive maintenance by vibration monitoring, the RWS pump that was overdue for overhaul did not have a vibration sensor installed down on the pump bowl. Past experience had shown that this was necessary for predictive information since vibration monitoring per the ASME Code was not an indicator of impending failure of a deep draft pump.

The instrument trending program was well run and effective. Calibration data for both balance of plant (BOP) and technical specification (TS) instrumentation was collected and trended. Details such as dead band and drift were evaluated and recommendations were made. For instance, recommendations were either made for switch replacement if drift became excessive or for increased calibration frequency. This program was one of the most productive the licensee had, but better proceduralization appeared to be necessary to ensure that the program would continue in the absence of key personnel.

The thermography and oil analysis programs had recently been started. The licensee was incorporating them into their predictive maintenance program slowly and deliberately, trying to incorporate the lessons learned by the rest of the industry. Although both these programs were in their inception, the licensee had already reaped some benefits from them. For example, thermography had been used to detect problems in iso-phase ducting and to ascertain proper operation of steam traps.

It was worth noting that the licensee placed primary responsibility for system performance on the responsible system engineer. Fully half of their system engineers were new to the site and the performance monitoring program procedures were also relatively new (approximately six months old). Better proceduralization of the performance monitoring program and better training of the system engineers would appear to be warranted so that even a new system engineer would know what information they should be receiving and from whom.

3.3 Coordination of Maintenance

DAEC, as were many licensees, was doing a great deal of maintenance while in a TS Limiting Condition for Operation (LCO). The licensee had a policy statement on LCO maintenance that provided management direction to the operations and maintenance departments regarding the performance of preplanned maintenance for which the TSs require entry into an LCO. As part of the review of the implementation of this policy the team evaluated the following event.

In June 1991, an annunciator associated with the diesel engine driven fire pump malfunctioned and a CMAR documented the failure. The CMAR specified to work the annunciator without isolating it. In July, a technician attempted to work on the annunciator with no isolation, and concluded this would not be possible. The CMAR was returned to planning, but the milestone on it was not changed to reflect that it had to be done as LCO maintenance. In September, an amendment to the TSs was issued that allowed one of the fire pumps to be taken out of service (OOS) for up to seven days. In late September, the licensee took the fire pump OOS to perform maintenance that had been delayed during the nine months the licensee had been waiting for the TS amendment. However, since the milestone on the CMAR for the maintenance of the annunciator had not been recoded as LCO work, when the computer generated the list of work requiring an LCO this item was not on it. The fire pump was taken OOS for about three days and LCO work was performed. In October, a diesel engine block heater malfunctioned and had to be replaced; a job that required the fire pump to be taken OOS. At that time, it was realized that the annunciator was also LCO maintenance and the licensee decided to work both in parallel. However, the temporary operations shift supervisor (TOSS) and the maintenance planner, who shared responsibility for writing and evaluating the required isolation, did not realize that the isolation for the heater was not compatible with the troubleshooting requirements for the annunciator. It was only after a technician tried to work on the annunciator that it was realized that different isolation was required. The licensee completed the work on the heater and returned the diesel engine driven fire pump to service. Several days latter, when a surveillance test was due that required the pump to be OOS, the annunciator work was accomplished.

Two breakdowns in the licensee's control system for LCO maintenance took place. First, when the CMAR was returned to planning, its milestone was not recoded to reflect the requirement to do it during an LCO. Second, when the TOSS and maintenance planner evaluated the required isolation, they did not realize that the isolation for the heater was not compatible with that for the annunciator. Generally, coordination of maintenance appeared to be adequate. However, as noted above, problems still occur on occasion.

3.4 Prioritization and Timely Performance of Maintenance Activities

The operations SS was responsible for establishing the priority of Maintenance Action Requests (MARs). The team reviewed in excess of two hundred open and completed MARs, including TS and safety-related, for appropriate prioritization and timely performance. Overall, performance in this area was considered adequate. However, it was noted that the licensee does not generally authorize overtime to support maintenance performed under an LCO. Current NRC guidance is that all reasonable efforts should be made to minimize the duration of maintenance related LCOs.

3.5 Maintenance Backlog

The current nonoutage backlog of CMARs was approximately 720 at the time of this inspection. While this level of backlog was considered acceptable, it was approximately 20% higher than the level at the same point in time during the licensee's previous fuel cycle. This apparent upward trend was due in part to a substantial loss of experienced staff (especially in the I&C shop) due to a reorganization.

The licensee, in an effort to reduce the backlog, authorized the working of overtime during the previous few months. This effort, combined with the pursuit of replacement staff and initiatives identified through the Maintenance Quality Improvement Program appeared to be effective in reducing the backlog.

The Maintenance Quality Improvement Program represented an effort by the licensee's staff to improve both the quality and efficiency of the maintenance function. This program provided for assigning an observer to analyze random maintenance activities. The observer developed a detailed observation guideline for the particular activity being observed. These guidelines generally addressed the broad areas of job planning activities such as MAR package preparation, tagouts, and radiation work permits; in-progress activities such as material and part availability, inspections, quality control, and health physics (HP) support; and post job activities such as maintenance testing, package closeout, and housekeeping. If appropriate, typical improvement follow-up actions included such things as procedure revisions, work package upgrades, personnel training, and improvement of inter-departmental communication.

The team reviewed the program and a sample of recent improvements initiated as a result. Improvements were noted in the staging of material and parts prior to initiating the maintenance activity and in the scheduling of HP support. The licensee's program was viewed as proactive and should result in an overall improved maintenance function.

4.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION

4.1 Management Oversight Activities and Accountability

As stated in the SALP 9 report, the licensee's approach to identifying and resolving technical issues from a safety standpoint appeared to be generally adequate. However, the SALP report did identify several concerns. As a result, the licensee implemented a number of new programs to correct the identified concerns. These programs generally seemed to be correcting the concerns, but the inspection was performed too early to allow the long term effectiveness to be evaluated.

Management personnel were interviewed and observed in their day-to-day activities. Their attitude towards operational safety, response to events, identification and documentation of significant deficiencies, and corrective actions appeared appropriate.

Management's concern for keeping the plant on-line versus its concern for safe operation of the plant seemed proper. However, as noted in the SALP 9 report, technical specification (TS) changes related to operational flexibility had previously received a greater priority than those that would correct nonconservative TS. The licensee appeared to have altered this priority, but correction of some TSs were still in progress at the time of this inspection.

4.1.1 Business Plan

The licensee had placed the problems noted in the SALP 9 report in the Nuclear Generation Division Business Plan. The business plan presented five year goals, strategies, and objectives for the operation of the facility. The business plan appeared to be a sound, well thought out, and well implemented mechanism to ensure good operation of the facility. The team discussed the business plan with numerous personnel in the engineering organization. Each person, from managers to individual engineers, felt that the plan represented a more focused approach to identification and control of tasks and to meet the overall objectives.

Certain goals, strategies, objectives, and individual tasks were selected for evaluation as to the status of their implementation and effectiveness. All of those that were selected were found to have been completed on schedule or the schedule had been appropriately adjusted. As of this inspection, no undue pattern of schedule slippage had been identified. Of those items selected for an evaluation of effectiveness, no problems were noted, with one exception. The team reviewed Goal 7, licensing, "Improve licensing performance to recover SALP rating of 2 or better", Strategy B, "Improve quality of TS and TS interpretations", Objective C, "Improve TS interpretation process", Task 2, "Develop and implement an NGD-100 level procedure to control the initiation, approval, and distribution of TS interpretations" for implementation. Four Technical Specification Interpretations (TSIs) were selected for review. Of the four TSIs evaluated, the team disagreed with two of them and identified a concern with the timeliness of resolving a question on a third as discussed below.

4.1.2 Technical Specification Interpretations

Part of the licensee's response to SALP 9, as stated in their July 24, 1991, letter, was "A new procedure governing the writing of TS interpretations has been prepared and is undergoing internal review which will formalize the process. We are re-examining existing written interpretations to assure that each has an adequate basis." The licensee's business plan had an internal commitment date for implementation of the procedure of October 30, 1991. Procedure 102.16 "Preparation, Review and Processing of Technical Specification Interpretations" was issued on October 10, 1991. Interviews with licensee personnel and statements in the July 24, 1991, letter showed that while the procedure was new, it merely formalized a pre-existing process that was not modified. This process consisted of a TSI being requested and submitted to either Nuclear Licensing or Technical Support. After the TSI was researched and written, the Manager, Nuclear Licensing, and the Assistant Plant Superintendent, Operations Support, reviewed, and if appropriate, signified approval. After the Operations Committee (OC) reviewed and concurred with the TSI, it would then be formally issued. During the review of this procedure the team developed a concern that Design Engineering was not involved in the initial review and approval of the TSIs. This was considered a weakness in the TSI process. While the implementation of the tasks under Objective C were completed on schedule, the improvement of the TSI process was not achieved. The new controls on TSIs were not rigorous and interpretations of TSs were neither consistently thorough nor conservative. This was evidenced by the findings discussed below and the continuing examples that were being identified by the NRC resident staff.

- The licensee had a question in regard to the use of the term 'trip system' and how many average power range monitors (APRMs) and intermediate range monitors (IRMs) must be operable to satisfy TSs.

  There were three instrument channels feeding Reactor Protection System (RPS) Bus A and three channels feeding RPS Bus B. Even with one channel in bypass in both busses, it would only take one channel feeding Bus A to trip, coincident with one feeding Bus B to trip, in order to trip the RPS (one out of two taken twice) and cause a reactor scram. The licensee's interpretation stated that TSs only required two of the three instrument channels on RPS Bus A or B to be operable. The TSI did not place a time limit on how long the channels could be placed in bypass. The team agreed with the licensee that for short durations this was acceptable, however the licensee had left two APRM channels in bypass during the entire current operating cycle (approximately one year). The team's view was that this violated the intent of the TSs as delineated in the TS basis. A discussion of the long term bypass of APRMs is included below and in paragraph 4.4.

On December 11, 1990, the licensee issued a revision to Operating Instruction Number 878.4, which stated, in part, that in order to prevent a full scram due to a single shared local power range monitor (LPRM) failure, APRM combinations of A & D or C & B should remain in the bypass position during normal operation. While having one channel in bypass does still allow for a single failure, the system of bypassing channels was not intended for continuously bypassing instrumentation channels for operational flexibility. Early in the operating cycle the licensee experienced a reactor scram due to an LPRM failing high. This particular LPRM was one which feeds both RPS busses. The existing design of the RPS lacked resistance to spurious trips. The licensee's response to this design weakness was to make use of bypass switches which were intended to be utilized for maintenance and surveillance purposes (i.e., brief periods of time), as long term corrective action. The licensee had been operating with these switches in bypass for approximately one year. Both the Updated Final Safety Analysis Report (UFSAR) and the TSs stated that the bypass switches were there for maintenance and surveillance activities. The licensee failed to perform a safety evaluation, or any other kind of justification, for operating in this configuration for an extended period of time. In addition, the licensee also failed to perform a safety evaluation prior to installing the new LPRM operational amplifiers (see paragraph 4.4 for details) even though the new amplifiers changed the way the system operated. NRC evaluation of these issues will be tracked as an unresolved item (50-331/91017-05). The team was also concerned that the level of protection from spurious trips as described in the UFSAR was no longer being satisfied. The licensee should evaluate the need to update the UFSAR to reflect the current trip system reliability.

- TS 3.7.D.2.b required that with one or more of the primary containment isolation valves in a penetration inoperable that a second valve in that penetration be maintained operable or isolated and, within four hours, either restore the inoperable valve to an operable status or "Isolate each affected penetration by use of at least one automatic valve locked or electrically deactivated in the isolated position," or by use of one manual valve locked in the isolated position or by use of a blind flange. The licensee's TSI defined, among other things, what steps must be taken to "lock" an electrically actuated valve. The licensee's TSI stated "Valves that have key lock hand switches are considered "locked" if the hand switch is locked such that the valve is in the closed position and cannot automatically open."

The team disagreed with this TSI. The TSI did not take into consideration the other alternatives to "locking" the valve. The valve must be placed in a condition such that no inadvertent electrical short, signal actuation, or electrical activity can alter the position of the valve. This position was previously communicated to the licensee by the NRC in Inspection Report 50-331/90023 and was documented as a Notice of Violation (50-331/90023-02). The teams review determined that the licensee had not had an occasion to use this particular aspect of the TSI. Failure of the licensee to comply with the locking portion of the TS would be a violation of the TSs. On October 23, 1991, in response to the team's concerns, the licensee deleted this TSI (see paragraph 4.2 for more information). In addition, the licensee informed the team that this position was intended to apply only to air operated valves and not to motor operated valves even though the TSI specifically stated that it did apply to motor operated valves.

- The TSs required annual verification that the inlet heaters for the standby gas treatment (SBGT) system were capable of producing at least 11 kilowatts (kw). A question had been raised by the licensee as to whether the 11 kw referred to the constant heater, to the variable heater, or both. On June 22, 1988, a contractor informed the licensee that 11 kw was nonconservative and tnat 22 kw should be utilized. The licensee took steps to ensure that the annual surveillance test verified that at least 22 kw were being produced by the heaters, and commenced an effort to resolve the discrepancy. The licensee's final resolution was to be a TS change request to define the 11 kw to be per heater for a total of 22 kw. This change was planned for submittal to the NRC by March 31, 1992. The team considered that a delay of four years to resolve a possible nonconservative TS was excessive.

4.2 Self-Assessment Capabilities

The team attended the off-site Safety Committee meeting held on October 16, 1991. The Safety Committee appeared to be very effective with a good interchange of information taking place. The team also attended the OC meetings held on October 22 and 23, 1991. While no significant procedure changes or major safety-related modifications were reviewed by the OC, the items that were reviewed, with the exception of the item noted below, received an appropriate amount of discussion.

During the October 23, 1991, OC meeting the licensee discussed the TSI on TS 3.7.D.2.b (discussed previously in paragraph 4.1.2). During that meeting licensee personnel discussed the intent of TS 3.7.D.2.b and what boundary should be used when electrically isolating a containment isolation valve. The discussion was at first focused on the use of a key lock hand switch as a "lock" but quickly grew into a discussion of what was intended by the TSs, the NRC, and what should the valve opening circuit be protected from. This sort of discussion was indicative of, and supportive of, sound TSIs. Just as it looked as if the discussion might result in a clear and valid conclusion, representatives from Nuclear Licensing refocused the groups attention to the narrow question of whether or not key lock hand switches could be used as electrical deactivation points. The team viewed that a correct understanding of TSs can only be accomplished with a complete and open discussion by a multi-disciplinary review group of all the issues related to a particular TS.

The licensee was not required to have, nor did it have, an Independent Safety Engineering Group.

One indication of a licensee with effective self-assessment capability would be an absence of recurring problems. As noted in this and other reports, the licensee has had recurring problems with TS compliance, procedural adherence, and the adequacy of the engineering organization. Corrective action in regards to these issues have been implemented and appeared to be a positive influence.

4.3 Quality Assurance and Quality Control Involvement

Quality assurance (QA) and quality control (QC) involvement in plant activities seemed to be well implemented. The movement of the QA audit group to the site and the increase in staff appeared to continue to be a strength. The number of outstanding quality assurance findings had been reduced and was steadily trending down.

The licensee's QC program was found to be satisfactory. The QC group was experienced, capable, and competent. Programs appeared to be being implemented in accordance with commitments and regulations.

4.4 Corrective Action Programs

A review of the licensee's programs for identifying, documenting, and correcting problems was performed. Random samples of nonconformance reports (NCRs), corrective action reports, audit findings, deficiency reports, surveillance reports, and corrective maintenance action requests were selected for review. In general, corrective action taken for each identified problem appeared appropriate. An adverse trend of NCRs being extended beyond the normal 30 day closure time was observed. This trend, while increasing, was significantly less than what existed six months earlier.

The team noted that the licensee had not always ensured that corrective actions were carried out in a timely manner. One example of this was:

- During the review of the APRM bypass issue discussed earlier, the licensee informed the team that one of the root causes for bypassing the APRMs was due to upscale spiking following the re-energizing of the RPS power supplies to the APRMs. This problem was first identified on July 9, 1985, and documented in Licensee Event Report 331/85-034. Some operational amplifiers in the LPRM circuitry were saturating upon re-energizing of the RPS power supplies, causing an upscale high trip. This was determined to be due to a new type of replacement operational amplifier. Since the vendor (GE) no longer manufactured the old style of operational amplifier, over the years more and more of the old style amplifiers were being replaced with the type with the new failure mechanism. Service Information Letter (SIL) 445, Supplement 1, Revision 1, issued June 14, 1991, offered the licensee a long term solution to this problem. The licensee was scheduled to implement a design change (DCP 1523) to correct this problem during the next refueling outage (February 1992) if the necessary parts were received in time. However, if parts are not received in time, the design change would be delayed until the 1993 refueling outage.

Another example of a delay in corrective action was the resolution of the SBGT heater TS requirement discussed in paragraph 4.1.2.

4.5 Commitment Control Programs

The licensee had a computerized commitment control process. Previously, there had been instances of the commitment control program failing to ensure that corrective actions to known, or suspected, plant problems were implemented in a timely manner. During this inspection several examples of untimely corrective action were identified, including the SBGT heater problem and the APRM issue discussed above, and the resolution of the ESW flow data discussed previously in this report (paragraph 2.1.1). Difficulties in the control of internal licensee commitments continued to persist.

4.6 Root Cause Analysis

The team evaluated the licensee's root cause determination programs through a review of plant procedures, interviews of personnel, and the analysis of a sample of formal root cause analysis performed by the licensee. Due to the previous procedure being too cumbersome, the licensee had modified the formal root cause analysis procedure to be less detailed.

During the June 1991 maintenance outage, galling was noted on the stem of the C outboard MSIV and the C inboard MSIV failed a local leak rate test (LLRT). The team reviewed the root cause report, dated September 13, 1991, for these events and found that it had been well prepared. For the stem galling, the root cause was determined to be a poor reassembly of the valve leading to a scrape or scratch on the stem. Followup actions included upgrading the maintenance procedure and a previous commitment to the NRC to disassemble the valve during the next outage to look for the possible cause of the damage. For the failed LLRT, the licensee determined that the most probable cause was that the disc pads installed to guide the disc into the seat were misaligned. The valve had passed an initial LLRT following the modification but the system engineer stated that there may have only been line contact and that once the initial seating surface was worn, the leakage path was opened. Corrective actions included performing a study to evaluate the cause of the misalignment and to try to identify better machining techniques. These actions appeared to have been appropriate.

4.7 Operating Experience Feedback

The licensee's operating experience review (OER) program was in the process of being centralized at the facility. This was being done to more efficiently weed out nonapplicable information prior to it being given to working level organizations. The previous backlog of approximately 200 OER items had been reduced to about 50. A number of NRC notices and Bulletins were selected for review with no significant problems noted.

5.0 OPERATIONS

5.1 Operations Control Of Support Activities

Daily plan of the day (POD) meetings were held with good attendance and wide participation by DAEC departments. This was considered a strength. In order to evaluate the effectiveness of the POD the team attended approximately 8 POD meetings. While the meetings were well attended by appropriate levels of management the team observed that little accountability was required by management when commitments were not met and when dates slipped. The cognizant individuals and departments also did not demonstrate responsibility for ensuring that commitments and dates were met or a valid reason provided.

During the inspection, the team toured various portions of the plant. Generally, the material condition of the plant and housekeeping appeared very good. Of particular note in this regard was the torus area. The team did note that the licensee had, over a period of time, recovered much of the contaminated portions of the plant. However, it was also noted that the recent trend in this area was unfavorable. Of particular note in this regard were the recent contaminations of three emergency core cooling system rooms and the reactor core isolation cooling system rooms.

6.0 OPEN ITEMS

Open items are matters which have been discussed with the licensee which will be reviewed further by the NRC and which involve some action on the part of the NRC or licensee or both.

An open item disclosed during this inspection is described in Paragraph 2.1.3.

7.0 UNRESOLVED ITEMS

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, items of noncompliance, or deviations. Unresolved items identified during the inspection are discussed in Paragraphs 2.1.1 and 4.1.2.

8.0 EXIT MEETING

The Inspection Team met with the licensee representatives denoted in Appendix A at the conclusion of the inspection on October 25, 1991. The Team Leader summarized the purpose, scope, and findings of the inspection and the likely informational content of the inspection report. The licensee acknowledged this information and did not identify any information as proprietary.

APPENDIX A

ATTENDANCE SHEET

EXIT MEETING - OCTOBER 25, 1991

NAME	TITLE
Licensee Personnel	
R. McGaughy	Vice President - Production
D. Mineck	Manager, Nuclear Division
D. Wilson	Plant Superintendent Nuclear
R. Salmon	Manager, Nuclear Licensing
M. Flasch	Manager, Design Engineering
R. Anderson	Assistant Operations Supervisor
G. Kaegi	Operations Shift Supervisor - Licensing
T. Browning	Supervisor, Nuclear Licensing
B. Lacy	Manager, Long Range Planning
B. Bernier	Engineering Practice and Evaluation
D. Lausar	Supervisor, Project Engineering
J. Probst	Technical Support Engineer
J. Thorsteinson	Assistant Plant Superintendent (APS) - Operations Support
G. VanMiddlesworth	APS - Operations and Maintenance
L. Mattes	Nuclear Fuels
P. Serra	Manager, Emergency Planning
T. Wilkerson	Manager, Radiation Protection
W. Miller	Supervisor, Analysis Engineering
R. Potts	Supervisor, Plant Procedures
S. Swails	Manager, Nuclear Training
G. Sharp	Manager, General Operations - Central Iowa Power Cooperative (CIPCO)
G. Gerdes	Generation Engineer - CIPCO
O. Olson	Group Leader, Design and Component Engineering
N. Sikka	Supervisor, Design and Component Engineering
S. Shangari	Design Engineering
K. Fumau	Administrative Secretary
V. Crew	Technical Support Engineer
R. Baldyga	Supervisor, Maintenance Engineering
M. McDermott	Maintenance Superintendent
K. Young	Assistant Plant Superintendent
D. Robinson	Technical Support Specialist
C. Bleu	Supervisor, System Engineering
B. Klotz	Group Leader, Quality Assurance
M. Huting	Supervisor, Quality Control
K. Putnam	Supervisor, Technical Support
T. Erger	Group Leader, System Engineering
J. Hennings	System Engineering - Performance

NRC PERSONNEL

E. Greenman	Director, Division of Reactor Projects, RIII
R. Lanksbury	ction Chief, RIII
R. Hague	ction Chief, RIII
C. Shiraki	roject Manager, NRR
J. Jacobson	Reactor Inspector, RIII
B. Bartlett	Senior Resident Inspector, RIII
M. Parker	Senior Resident Inspector, RIII
W. Schmidt	Senior Resident Inspector, RI
C. Gainty	Reactor Inspector, RIII